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BOARD DECISIONS

1973 - 1974

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ENERGY RESOURCES CONSERVATION BOARD
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BOARD DECISIONS

1973 - 1974

ENERGY RESOURCES CONSERVATION BOARD
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ENERGY RESOURCES CONSERVATION BOARD

Decision 73-1
Proceeding No. 6272

PRESSURE MAINTENANCE BY WATER INJECTION AMBER - LARNE - VIRGO - ZAMA AREAS

HEARING

A hearing was held by the Energy Resources Conservation Board for the purpose of hearing representations concerning submissions respecting the matter of the feasibility of pressure maintenance of the Muskeg and Keg River Pools in the Amber, Larne, Virgo and Zama Fields (hereinafter collectively referred to as the "Zama basin"). In addition, the Board heard representations from well owners and other interested parties to show cause why the Board should not require the pressure maintenance of pools in the Zama basin.

The hearing was called by the Board of its own motion with D. R. Craig, P. Eng., Vernon Millard and V. E. Bohme, P.Eng. sitting, on July 25, 26 and 27, 1972.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Amoco Canada Petroleum Company Ltd.	D.J. Sandmeyer, P.Eng.	Amoco
Ashland Oil Canada Limited	E.P. Webb, P. Eng.	Ashland
Canadian Industrial Gas and Oil Ltd.	W.R. Brooke, P.Eng.	Canadian Industrial
Canadian Superior Oil Ltd.	R.W. Stanich, P.Eng.	Canadian Superior
Chevron Standard Limited	G.A. Johnson, P.Eng. P.V. Malowany, P.Eng.	Chevron
Dome Petroleum Limited	J.M. Stewart, P.Eng.	Dome
Gulf Oil Canada Limited	T.E. Randall, P.Eng. G. James	Gulf

	Represented by	Abbreviation Used in Report
Hudson's Bay Oil and Gas Company Limited	M.B. Field R.W. Hoover G. Norgard	Hudson's Bay
Imperial Oil Limited	D.E. Towson, P.Eng. R.J. Craig	Imperial
Petrofina Canada Ltd.	J. Wansleeben, P.Eng.	Petrofina
Skelly Oil of Canada Ltd.	S. Koles, P.Eng. J.J. Kirk, P.Eng.	Skelly
Sun Oil Company Limited and Sunray DX Oil Company	R.C. Egglestone, P.Eng. R.R.J. Derouin, P.Eng.	Sun
Texaco Canada Limited	I.E. Varga, P.Eng. R.M. Chaudhry	Texaco Canad
Energy Resources Conservation Board Staff	J.A. Bray, P.Eng. N.G. Berndtsson, P.Eng. H.C. Moster, E.I.T.	Board Staff

BACKGROUND

The Zama basin is a Middle Devonian evaporite basin approximately 18 miles wide and 30 miles long located in northwestern Alberta. Its longest axis is oriented in a northeast-southwest direction and it dips to the southwest. The basin contains several hundred small pinnacle reefs ranging in thickness from 300 to 450 feet.

The first oil production commenced in the Zama basin in November 1966 and to date approximately 300 pools have been declared by the Board. Most of the pools contain only one well, are relatively small in area and have been producing for more than four years.

As of December 31, 1971, 39.1 million stock tank barrels (39,100 MSTB) of oil, 16.9 million cubic feet of gas and 5.53 million barrels of water have been produced from the Keg River and Muskeg Pools of the Zama basin. The oil in place and recoverable oil reserves established by the Board for the basin were 618,000 MSTB and 203,000 MSTB, respectively, as of January 1, 1972.

The need for pressure maintenance has been under consideration since as early as 1968 in the Zama basin by both the operators and the Board. A review in 1971 revealed that some enhanced recovery applications were being submitted but generally operators were uncertain about pressure maintenance plans. Some integrated schemes were being considered but none involved joint operations. As of August 1, 1972, there were 56 pools in approved schemes of enhanced recovery by water flood, 49 of which were operating. Of these, 32 pools are in integrated schemes, 10 pools in schemes in which cycles of injection and production alternate in a single well (hereinafter referred to as "cyclic schemes"), 6 pools in which simultaneous injection and production are carried out in a single well (hereinafter referred to as "simultaneous schemes") and 8 pools in schemes with separate injection and producing wells for each pool.

In April 1972, the Board staff submitted a proposal to the Energy Resources Conservation Board for pressure maintenance of 80 per cent of the pools in the Zama basin by the injection of water. In May 1972 the Board issued Informational Letter No. IL-OG 72-8 to all operators in the Zama basin informing them of the subject hearing and its purpose.

By June 29, 1972, 15 summissions had been filed with the Board by operators in the basin. The submissions generally opposed the Board staff proposal.

DEFINITION OF ISSUES

The Board acknowledges that the scope of the hearing involved the consideration of a large number of variables, some being defined poorly. For the purpose of this report these variables are discussed in sections under major issues. As the Board sees it the major issues are:

(1) The need for pressure maintenance.

(2) The technical feasibility of pressure maintenance which requires consideration of:

  (a) the physical nature of the Zama basin, and

  (b) the performance characteristics in the Zama basin.

(3) The economic feasibility of pressure maintenance.

THE NEED FOR PRESSURE MAINTENANCE

(1) Views of Board Staff

The "Board Staff Study"[1] indicated that, following a basin-wide study of pool pressures using isobaric maps, approximately 70 per cent of the pools in the Zama basin were presently at pressures below their saturation pressures. Hence the Board staff contended that the majority of the pools in the basin were suffering losses in recoverable oil due to shrinkage effects. It also stated that the initiation of new pressure maintenance schemes was progressing slowly, most likely because the physical nature of the reef occurrences suggests the need for grouping of pools for the most efficient schemes. However, this is difficult due to the complex inter-pool pressure relationships in the basin. It was concerned that if pressure maintenance did not proceed soon, it would be too late to nullify what it estimated to be a continuing shrinkage loss of approximately 400 MSTB of recoverable oil per year.

The Board staff also stated that an estimated incremental recoverable reserve of 62,000 MSTB of oil would be conserved if its proposed basin-wide scheme were to be implemented now. A later start on such a scheme would render it less attractive economically because of increasing Provincial allowables and forecasted decline in basin productive capacity.

(2) Views of Operators

There was a considerable variation in the views of the operators as to the need for pressure maintenance in the basin. In most cases the views were confined to each operator's own pools and operation.

Most operators contended that the need for pressure maintenance should be considered on an individual pool basis or on a group of pools after careful consideration of production performance, pressure history and degree of inter-pool communication. The proposal of a basin-wide co-operative pressure maintenance scheme was almost unanimously considered to be premature and could in fact be detrimental to the ultimate oil recoveries in certain areas of the Zama basin.

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(1) Board Staff Submission included a report, "Feasibility Study of Pressure Maintenance by Water Injection, Zama Basin - February 1972".

It was acknowledged that reservoir pressure significantly below the saturation pressures and significant increases in producing gas-oil ratios would be indicators of the need for pressure maintenance. Many operators, however, pointed out that clear indications of shrinkage losses were not demonstrated by increasing producing gas-oil ratios in pools apparently operating below the saturation pressure. Gulf contended that because of the pressure build-up characteristics in the basin, the pressure surveys conducted on wells to date have, by and large, yielded only apparent reservoir pressures. These pressures are considered unrepresentative of the overall reservoir conditions and therefore would be poor indicators of the need for pressure maintenance in the Zama basin. Further, pressure data was considered to be an inadequate basis for measuring the success of water flood schemes in the basin. Many operators more or less agreed with Gulf's views on pressure data in the basin, however, the consensus was that measured pressures from survey to survey were useful on a relative basis.

An appreciable number of operators questioned the propriety of proceeding with pressure maintenance by water injection because of the increased producing water-oil ratios observed to be associated with existing schemes in the basin. In addition to this feature, Dome also expressed disillusionment with the general lack of improved oil productivity from pilot schemes. Chevron contended that additional production history was required to assess the relative merits of cyclic, simultaneous or co-operative pressure maintenance schemes for various areas in the Zama basin and to reduce the financial risks associated with the current high failure rate of pressure maintenance projects. Some owners contended that the potential for water flooding success must be good before taking the risk of jeopardizing primary production. Widespread installation of water flood should not be required by the Board before existing schemes have proven that, in most cases, meaningful improvements could be made to the productivity and ultimate recovery of oil. Some operators acknowledged that pressure maintenance could be attractive to individual areas of the basin where pool pressures have decreased significantly and inter-pool communication has been indicated by pressure data.

A few operators, notably Ashland, with pools on the periphery of the basin development, saw little need for pressure maintenance at this time because of natural water influx from the aquifer. However, they expressed the view that, should pressures decline significantly below the bubble point to the detriment of recovery from such pools, pressure maintenance would be considered on an individual pool basis.

Most submissions listed individual pools which should be exempt from pressure maintenance because of very low reserves, poor productivity, poor production performance with respect to water-oil or gas-oil ratios, and other factors which would lead to a very marginally economic operation.

(3) Views of the Board

The Board is of the opinion that the need for and timing of pressure maintenance is of major concern in light of the issues involved in this hearing. Under normal circumstances the need for installing pressure maintenance in a pool is to maintain or increase well productivity and to curtail the loss of recoverable oil due to shrinkage effects when the oil in the reservoir drops below its saturation pressure. In addition to low pressure, an increase in gas-oil ratio is also taken as an indicator that shrinkage is occurring and that pressure maintenance may be needed.

The Board recognizes that the shrinkage losses estimated by the Board staff are directly related to the validity of the pressure measurements in pools in the Zama basin. As pointed out by many operators, the absence of increased producing gas-oil ratios places some doubt on the validity of measured pressures. As discussed later, the Board is of the opinion that a reasonably built-up pressure closely approximates the pressure of the effective oil in the system. If such pressures show a decline below the saturation pressure, the Board believes the effective oil in the pool is undergoing shrinkage losses.

Another factor the Board considers important in determining the need for pressure maintenance is the shape of the reservoir. Assuming the "mushroom shaped" oil reservoir (1) is composed of relatively homogeneous rock, the optimum area and thickness of the terminal oil sandwich would be at the top of the reservoir. This would require bottom displacement by water, either by natural influx or by injection, preferably at or just below the saturation pressure.

The Board agrees with what appears to be the understanding of most operators, that the productivity aspect of pressure maintenance is of less importance in the Zama area due to the relatively high productivities in relation to oil reserves in the majority of the pools in the basin. However, sustained productivity in the future could be important both for economic and conservation reasons. It should also be noted that vertical displacement floods normally do not affect well productivity as much as horizontal floods.

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(1) Decision 70-7

The Board agrees with its staff that timing is of major concern since shrinkage losses are not reversible. However, as pointed out by many operators, the risks involved in initiating pressure maintenance schemes must be assessed.

Having regard for the fact that some shrinkage is occurring, the effect of pool shape on recovery and recognizing that future productivity could be important, it appears to the Board that there is a need for pressure maintenance in most pools in the basin. Certainly the long term indications are that pressures will decrease appreciably in the basin. However, the Board accepts that with the apparent risks involved, careful appraisal is necessary of the technical and economic feasibility of injecting water to maintain pressure in the Zama basin or in specific areas of the basin.

THE TECHNICAL FEASIBILITY OF PRESSURE MAINTENANCE

(a) The Physical Nature of the Zama Basin

(1) Views of Board Staff

The Board staff stated that the bottom 50 to 100 feet of the reefs and the inter-reef area form a continuous platform that has fair to good porosity. It based this statement on the fact that pressure communication is evident between many of the pools in the basin. Logs and core data have consistently shown the Zama Member to be tight in the inter-reef area, hence communication is inferred to be through the lower portion of the Upper Keg River Member. It contended that a limited amount of core data indicated porosity and permeability in the inter-reef areas of the Upper Keg River Member in the basin.

The Board staff stated that the majority of the pools in the Zama basin are in communication with a continuous but finite aquifer which has provided some natural water drive. The aquifer continues to provide some water drive to pools located along the periphery of the basin, but the contribution of the aquifer to pools situated in the central area of the basin has diminished considerably. Pressures in the central area will continue to decline unless additional water is injected in the interior of the basin to augment the aquifer effects.

The Board staff contended that a good degree of pressure communication existed between pools in the basin. It substantiated this contention by listing 115 pools which had either shown a decline in initial pressures of more than 100 psi from that of the basin initial pressure or else had shown pressure response from water injection in neighboring pools. These pools were judged to be in communication with one or more other pools or groups of pools. The staff also had observed in its material balance studies, of pools in the basin, that some pools had shown reservoir pressure declines with no coincident production from the pool.

With respect to measured pressures in the Zama basin, the Board staff stated that present build-up times range anywhere from a matter of hours to a matter of months. Further, due to the nature of the basin, no particular extrapolation technique is satisfactory to determine static pressures and in most wells, even after sustained periods of build-up, pressures continue to increase. In explanation of apparent pressure performance in the basin, the staff suggested that significant energy is contributed to the system by the underlying inter-reef aquifer. Due to the generally low permeability exhibited by the inter-reef core data available, the aquifer would provide, over a large area, an unsteady state transient pressure response in the producing wells.

The Board staff stated that the present primary recovery factors are based on the assumption that the oil-water contact will rise with production because of aquifer expansion. If the pools were either acting as separate systems or receiving a very slow unsteady state pressure response from the aquifer, then, with water production from the pool, the oil-water contact would in fact be depressed resulting in a loss of oil due to residual oil saturations and hence lower recoveries than are presently expected. Therefore, all produced water should be returned to the system from which it originated.

The Board staff stated that the diverse ownership in the Zama basin together with an inability to unitize had been indicated by owners as a problem in initiating pressure maintenance schemes. Technical and economic factors along with the potential risk associated with single pool schemes make such schemes unattractive. As a result the Board staff considered the best means of pressure maintenance in the basin to be a basin-wide scheme or several integrated schemes among communicating groups of pools.

(2) Views of Gulf

Gulf presented a study (1) of the pools in the Zama basin operated by Gulf. Its purpose was to develop a composite geological model of the Keg River and Muskeg Pools. The study was limited to a comprehensive consideration of the reef proper at Gulf owned wells and did not consider other wells or the inter-reef areas of the basin. Gulf contended that a typical reef in the Gulf operated area of the Zama Field developed as an inner and an outer reef. According to the study, the "inner reef" is composed of reservoir rock having good permeability and providing excellent vertical communication with the lower reef bank and crinoidal platform within the Upper Keg River Member. The inner reef was found to be within the crestal area of the pool on the most agitated side of the reef, with that side being to the south-west, and representing 1 to 5 per cent of the oil in place. The "outer reef" or shell surrounding and overlying the inner reef was found to consist of highly stratified reservoir rock containing numerous bands and lenses of very good reservoir rock quality interspersed with relatively impermeable layers. Gulf indicated that it had not been able to develop a fully satisfactory geological model for its wells in the Virgo Field.

Gulf's analysis indicated that an active natural water drive is evident throughout most of the basin and concluded that a natural water drive index of 67 per cent was appropriate for its model studies of pools in the Zama Field. The Zama basin was considered to have a partial natural water drive index of the order of 50 per cent. Based on the data Gulf had looked at, it concluded there are probably many pools which were subject to some degree of interference through the Upper Keg River Member.

With respect to pressure data, Gulf contended that the pressure build-up characteristics in the Zama basin yield apparent reservoir pressures that are not representative of the overall reservoir condition. It was critical of current methods of pressure analysis and concluded that infrequent comprehensive surveys with the survey procedures standardized would improve the pressure survey results and usefulness. The recommended frequency would be every three years or after production performance indicates a significant change in reservoir depletion mechanism with minimum shut in times of 120 hours.

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(1) Gulf submission included a report, "Water Flood Feasibility Study, Zama Field - June 1972", J.F. Bechtold and T.E. Randall, Gulf Oil Canada Limited.

Provided the shut-in time was long enough, Gulf contended that the reservoir pressure of a pool in the Zama basin would build-up to near the initial reservoir pressure.

Gulf attributed the pressure build-up phenomena to either the inner-outer reef concept or to unsteady state aquifer response or to both, but rejected the impermeable Zama marker as being responsible for the observed pressure build-up behaviour.

(3) Views of Ashland

Ashland stated that Gulf's inner-outer reef concept could explain the water-oil ratio production performance in two of its twelve pools. A substantial natural water drive existed on the eastern edge of the basin where most of its wells are located. It concluded that seven of its twelve pools had pressures being sustained by the aquifer.

Ashland had misgivings regarding the representativeness of the current pressure measurements in the basin. It used relative pressures as one measure of pool performance but considered productivity a better indication of performance.

(4) Views of Canadian Superior

Canadian Superior did not consider communication in the basin to be adequate for large scale water flood operations but stated that a few small areas showed some positive prospects based on initial pressure data, interference and pilot tests.

Canadian Superior agreed there was some substance to Gulf's inner-outer reef concept as far as basic reef growth was concerned and as a possible explanation of the pressure phenomena. It concurred with Gulf's contention of a long term pressure transient that required an extremely long period of build-up to reflect pool average pressure conditions.

(5) Views of Chevron

Chevron stated that the majority of its pools were experiencing some degree of natural water influx but only limited areas had sufficient inter-pool communication to obtain satisfactory flood response from a scheme such as proposed by the Board staff.

There are many pressure abnormalities in the Zama basin and these abnormalities could possibly be explained by limited communication between the Keg River and Muskeg zones. Chevron was not sure the observed deflections in build-up curves were caused by reservoir boundaries or by Gulf's inner-outer reef concept.

(6) Views of Dome

Dome stated that most of the pools it operates in the north-east portion of the basin were in communication through the aquifer.

Dome considered Gulf's inner-outer reef concept to have merit, especially in relation to explaining Dome's water production problems. The concept was less satisfactory in explaining the pressure build-up phenomena. Pressure build-up characteristics could be attributed to the Z marker and other dense layers in the Zama Member. Since most of the wells operated by Dome were completed in the Zama Member, some above and some below the Z marker, it appeared that pressures reflected limited vertical communication rather than the effects of an inner-outer reef.

There is considerable doubt as to the validity of some pressure surveys in the Zama basin. Pools at high pressure levels probably had reached a stable pressure stability, but those at low levels usually exhibited a slow build-up and could require time periods in the order of six months to a year to fully respond. Dome concluded that less frequent pressure surveys, possibly at two year intervals, would be appropriate, especially on pools with small reserves.

(7) Views of Hudson's Bay

Hudson's Bay contended that Zama basin pools are not in communication through the Keg River inter-reef build-up, but submitted that localized regions of limited interference do exist, likely because of some inter-reef communication through the crinoidal banks formed near the interface between the Upper Keg River and Lower Keg River Members.

Hudson's Bay claimed its area of operation differed from the rest of the basin with respect to the degree of aquifer communication. Talus material deposits decrease as the distance from a reef increases. Accordingly, porosity and permeability, associated with the talus material, would decrease in the inter-reef area with increasing radial distance from a reef. The reefs in Hudson's Bay's area are generally larger in size with greater distances between them compared to the rest of the basin. Because of the greater distances between its reefs, Hudson's Bay concluded that significantly less inter-reef reservoir rock had any effective porosity and permeability.

Although declining initial pressure data indicate that leakage had occurred due to communication with neighboring producing pools, the rate of transfer may not approach the rate necessary to use the same pool as an injection well to pressure maintain a number of other pools.

Material balance calculations indicated to Hudson's Bay, that some pressure energy is supplied by aquifer water expansion, but the magnitude of this energy is not large enough to be called a real water drive, and perhaps only a limited volume of water is associated with the reef. In general the pressure data in Hudson's Bay's area leads to a reasonably reliable relatively uniform and predictable trend with time. In this area of the basin measured pressures, relative one to the other with respect to time, generally give a good indication of pool performance.

Hudson's Bay stated it had not studied Gulf's inner-outer reef concept enough to render a positive opinion but it would not discount the concept. It contended that the Z marker was not as pronounced in its area of operation as in the remainder of the Zama Field. Where the Z marker existed, Hudson's Bay generally completed the wells below or through it; consequently the Z marker was not a factor restricting pressure build-up in its wells.

Hudson's Bay concluded from model runs that a 100 per cent water drive index would not give quite as high a recovery as a 75 per cent water drive index. Hudson's Bay acknowledged this to be contrary to the findings presented in the "Gulf Study".

(8) Views of Imperial

Imperial stated that pressure profiles, and absolute pressure levels, are not a good indication of communication based on the performance of its Integrated Scheme (I.S.) No. 4. Low initial pressures are perhaps one good indicator of communication but it is difficult to ascertain the pool or pools that may be in communication with the pool having the low initial pressure. Imperial has observed that a considerable length of time is needed for a fully built-up pressure in the area. Based on the pressure data in I.S. No. 4, no response is apparent in any well over half a mile from the injector.

In Imperial's view there are three types of pools in the basin:

(a) Pools connected to a fairly large aquifer and are pressure maintained.

(b) Pools completely isolated or connected to a very small aquifer which has no effect on the pressure of the pools.

(c) The majority of the pools are interfering with other pools but these interference groups could consist of anywhere from two to five pools and may or may not be in communication with either other groups or a large regional aquifer. Imperial could not decide if the lack of communication was because a group was not connected to the aquifer or if there were some discontinuities in the aquifer.

Imperial considered that approximately two-thirds of the pools in the Virgo Field were in communication with one or more other pools.

Respecting Gulf's inner-outer reef concept, Imperial claimed to have noted some evidence of differing properties in Zama reefs from one side to the other, but have not done any work to attempt to directionally orient such properties nor has Imperial studied facies types or absolute permeability levels in regard to position within a reef.

(9) Views of Skelly

Skelly subscribed to the theory that pools in some areas could be pressure maintained through a common aquifer. The long periods of pressure build-up could be attributed to either the slow flow of oil from the tighter flank area of the pool into the main reef zone or a slow influx of water from the aquifer.

(10) Views of Sun

Sun stated that, of twelve of its pools remaining under primary depletion, four could be considered as water flood candidates from a technical standpoint.

(11) Views of Texaco Canada

The absence of effective inter-pool pressure communication, in Texaco Canada's view, can be determined in most cases by a chronological comparison of pool pressures. In most of Texaco Canada's area of operation, there has been no evidence of effective inter-pool communication. In order to use initial pressure data to show effective pressure communication, the initial pressure of the pool must match the pressure of pools with which it is communicating. Two areas within its region of operation indicate some degree of communication, and Texaco Canada intends to make application to conduct pressure interference tests in these areas to determine evidence of positive communication between pools before initiating integrated schemes.

(12) Views of Other Operators

Amoco, Canadian Industrial and Petrofina all had views pertaining only to their own specific pools.

(13) Views of Board

In regards to the various geologic interpretations of Zama Keg River and Zama Member geologic structures the Board is of the view that the Keg River reefs built-up from a more or less continuous crinoidal platform. The Board believes the evidence shows that either the Upper Keg River Member or the crinoidal platform are generally providing pressure communication between reefs. This is based on limited inter-reef core data, upon evidence of continued pressure support at the periphery of the basin, and numerous cases of inter-pool communication. However there appears to be an occasional permeability barrier between small individual pinnacle reefs.

Core data available on the inter-reef portion of the basin indicates the Upper Keg River Member to have porosity and permeability. Five out of ten cores from wells in undefined pools were considered by the Board to be from true inter-reef areas. Of the nearly 400 feet of core analysed from these five wells, footage weighted porosities and permeabilities ranged from 3 to 8 per cent and 13 to 314 millidarcies, respectively.

To determine the applicability of the Gulf study and concepts to the Zama basin the Board investigated all the core data available in the Zama basin. An effort was made to determine if there is a correlation indicating a relatively low magnitude of permeability in outer reef core compared to inner reef core. Seismic information was available to the Board on 25 wells which provide a reasonable distribution of centre crest, crestal and crest edge locations in the basin and on which reasonable core coverage existed. The core data of the 25 wells were analysed as to Zama Member, Keg River oil zone and Keg River aquifer for each well and categorized as to centre crest, crestal and crest edge along with general direction. Figures 1 and 2 show the results of the investigation for the Zama Member and Keg River Member respectively. Table 1 shows the footage weighted averages of porosity and permeability for some 13,000 feet of analysed cores from the entire Zama basin. The results shown in Table 1 and Figures 1 and 2 had upper and lower permeability cut-offs of 6000 and 0.01 millidarcies applied. Results without the lower cut-off were not significantly different. The investigation showed a central reef core with good porosity and permeability. While values for porosity and permeability decreased off centre crest the Board concluded they did not show any significant support for an inner-outer reef concept as proposed by Gulf. The Board accepts the existence of an inner and an outer reef on a macroscopic basis but cannot accept that the outer reef is very poor permeability material as contended by Gulf.

Previous submissions to the Board from both Hudson's Bay (1) and Imperial (2) presented geological studies of Zama basin reefs which generally showed a central Keg River reef area with porosity better than the edge areas but not to the extent necessary to give validity to the Gulf inner-outer reef concept.

The Board has evidence in some 70 cases of pools that were drilled later than neighboring pools and were found to have initial pressures measurably lower than the earlier developed pools. In some 40 cases pools have shown a positive pressure response subsequent to commencement of injection to adjacent pools. The Board concludes there are many areas of inter-pool communication throughout the basin. The Board acknowledges that the degree of communication or the lateral extent of such communicating areas is poorly defined at this time.

With respect to the pressure data obtained in the annual basin-wide pressure surveys the Board agrees, based on limited extended pressure data, that the pressures are probably not fully built-up. However, the Board does not agree with the explanation proposed by Gulf that pressures would build-up close to initial pressures due to gradual pressure equalization from the oil contained in the high pressure low permeability outer cores of the reefs.

Examination of core analysis data from the 13,000 feet of core mentioned previously failed to discover sufficient outer reef core of low permeability to explain the slow pressure build-up. Consequently, the Board concludes that pressure build-ups of about 5 days, which is representative of more than half of the build-ups in recent Zama basin pressure surveys, will provide pressure information that is at least representative of the oil which would be economically recoverable from a particular Zama reef oil accumulation. The Board expects that the pressure would continue to build-up with time, but would attribute such response to an unsteady state response from the low permeability inter-reef aquifer. This is not to say, however, that particular pools are not in effect separate systems or that a particular pool would continue to show a decline in pressure due to interference with other producing pools. The Board further notes that in particular areas of the basin the well completion relative to a largely impermeable Z-marker, or location of a well on the poor permeability Zama flank, may result in extended pressure build-ups.

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(1) Application No. 5065 - "An Engineering Study of Primary Depletion and Enhanced Recovery Schemes Zama-Virgo Fields" by Hudson's Bay, March 1972

(2) Proceeding No. 4865 - Annual Reserves Hearing, Virgo Keg River C Pool, January 19, 1970.

Gulf proposed a decrease in the frequency of pressure surveys in the Zama basin with a suggested minimum shut-in time of 120 hours. Dome also suggested less frequent surveys especially for small reserve pools. The Board regulations currently require that pressure surveys be taken every year on pools in the basin. This frequency was established when the co-ordination of a basin-wide pressure survey was achieved. Most wells included in the current pressure surveys in the basin have shut-in times of 120 hours or more. Also all pools are not surveyed annually. The frequency of survey is considered by the Board when each proposed annual pressure survey program is reviewed. The Board concludes that full adoption of Gulf's proposal would not achieve the objective of better quality data. Further study is warranted to determine the validity of present measurement techniques and possible changes to them. The Board urges that operators make efforts to improve the quality of pressure data in the basin. Meanwhile the Board believes pressure survey requirements should remain as stipulated under section 11.102 of the Oil and Gas Conservation Regulations as amended in July 1972.

(b) The Performance Characteristics in the Zama Basin

(1) Views of Board Staff

The Board staff position was that water production may be an uncontrollable characteristic of the pools in the basin, but that there was no conclusive evidence, except in cyclic schemes, that water flooding has caused or accentuated water production problems. Whatever the reason for water production in the basin, the staff contended that it occurred in spite of, rather than because of, water injection. Approximately 80 per cent of the wells in the basin have produced water, and the rate of water-oil ratio increase in pools converted to pressure maintenance followed the same trends after water injection commenced as before, with a few notable exceptions. For those pools that started producing water after injection commenced, the performance was not unlike the performance of other wells in the basin not subject to water injection. The water production could be a result of either poor well completions or water coning.

Coning appeared to be a likely cause, because nearly all wells in the basin were initially produced at high rates, as a result of 160 acre reserve assignments, possibly resulting in some damaging effects on the flow characteristics of the reservoir near the well bores. Also, the practice of producing the entire monthly allowable within a few days of the month was considered by the Board staff to be a contributing factor.

With the exception of a few pools, the Board staff had not observed significant increases in producing gas-oil ratios in the Zama basin as might be expected when reservoir pressures drop below the bubble point. Few pools in the basin were more than 100 to 200 pounds per square inch (psi) below the bubble point; therefore, little excess solution gas has been released. It is conceivable that the released solution gas could exist in the form of an immobile gas saturation, some may be trapped behind permeability barriers and some may have percolated to the top of the structure without being drawn to the well bore. As for the relatively few pools where the measured pressure indicates the pool to be significantly below the saturation pressure, the Board staff admitted to an inability to explain why producing gas-oil ratios have not increased.

With respect to the performance of pressure maintenance schemes and pilot tests, the Board staff was generally satisfied with the results. It contended that some cyclic type schemes appeared to have performed poorly in their initial stages. A lack of experience as to the optimum operating procedures appear to have given a poor first impression and should not result in condemnation of all cyclic schemes. Subjecting low reservoir pressure cyclic scheme pools to initially high rate water injection, which caused high injection pressures, resulted in extreme radial pressure gradients in the reservoir. This sometimes resulted in substantial water production in initial stages of the production cycle. Although some integrated schemes include pools that apparently have not received pressure response, it was considered too early to conclude that results were negative. Also, a significant number of pools outside many schemes are showing pressure response.

Regarding inter-pool communication, the Board staff interpreted the results of pilot tests, notably those of Dome, as well as presently operating integrated pressure maintenance schemes, to show sufficient proof that communication exists to make a basin-wide flood feasible. It agreed that specific areas appear to be isolated and that most peripheral areas of the basin appear to have adequate natural water drive to partially pressure maintain the pools at this time.

(2) Views of Gulf

Gulf attributed the performance of the producing wells in the basin, with respect to water production, to preferential flow channels provided by an inner and outer reef. Further, the severity of the water production problem was dependent upon the location of the well and its completion interval, relative to the inner reef. Water is produced by the preferential displacement of water, assisted perhaps by some coning of the water-loaded lenses that are in communication with the inner reef. Gulf concluded from its model studies that variations in water production performance within its area of operation in Zama resulted primarily from the macroscopic variation in communication between the well completion interval and the aquifer. Location of the completion interval with respect to the distribution of reservoir facies within the reef and particularly with respect to the degree of communication with the inner reef, was important.

From results of its study, Gulf found that cumulative water production correlated to cumulative oil production as a set of approximate straight-line functions on semi-log graph paper. From an analysis of water-oil ratio performance from eight pools it developed an equation, shown in Appendix A, relating cumulative water-oil ratio to both cumulative oil production and time. The sum of the constants, A, B and C, from this equation, was referred to as the "coning index" and was found to be a measure of the rate of increase in water production rate. Gulf also contended that a direct relationship existed between the "coning index" and the position of the well with respect to the south-west edge of the Keg River reef crest. Further, it stated that production performance data indicated that water flood success probably could not be attained at wells having coning indices greater than 20.

Gulf contended that the measured bottom-hole pressures in the interior of the Upper Keg River Reef Member represents only the subsisting pressure in the immediate limited drainage volume of the wells. This explained, in Gulf's view, why minimal volumes of excess gas are being produced in the Zama basin.

(3) Views of Ashland

Ashland stated that water-oil ratios will be affected by water injection in any area where there is water underlying the oil column. None the less, where bottom-hole pressure had declined below the bubble point or productivity had seriously decreased, it would still consider such pools on an individual basis as possible candidates for pressure maintenance by water injection.

Based on its experience with a cyclic scheme, Ashland was doubtful that it would ever initiate such a scheme again.

(4) Views of Canadian Superior

Canadian Superior expressed the opinion that water production performance in the Zama basin was indicative of significant completion or coning problems. Recompletion attempts have been very costly and have had limited success. It stated that water has coned to heights in excess of 100 feet above the oil-water contact and that reduction in producing rates has little sustained effect in alleviating producing water-oil ratios.

A review of existing water flood schemes in the Zama Field indicated, in Canadian Superior's view, generally disappointing performance. In most instances pressure response was evident but was accompanied by increasing water producing trends. Pressure maintenance by water injection may not result in significant improvement in recovery and in some cases may reduce the ultimate recovery to below that expected under primary production because oil could be bypassed in the basal portion of the reef due to high pressure differentials being created between the aquifer and the producing zone.

Canadian Superior stated that Gulf's inner-outer reef concept may have some validity in explaining some water production problems.

Having regard for the performance of the pools in the basin at the current level of recovery, Canadian Superior expressed some doubt that the currently established primary recoverable reserves would be realized.

(5) Views of Chevron

Chevron stated that natural water influx, or water influx induced by regional pressure maintenance, may contribute to early water production in many pools. It based this view on the high incidence of early water production in pools receiving some support from the underlying Keg River aquifer and also on the results of its pilot water injection project. Depending on where the wells were positioned in the reef, the creation of a gas cap by gravity segregation and the encroachment of water at a more modest rate than from full pressure maintenance could result in higher ultimate recoveries than those predicted under full pressure maintenance.

(6) Views of Dome

Dome stated that Gulf's inner-outer reef concept could have merit in explaining Dome's water production problems.

The results of Dome's water injection schemes showed many cases of pressure response and good communication through the aquifer but Dome had noted virtually no improvement in oil productivity. Water-oil ratios increased during the injection period. Dome did not know whether increasing water production was occurring in spite of or because of injection. It was disappointed in the results of its pilot injection scheme because it had not observed a decline in water cuts nor significant improvement in oil productivity. Dome concluded that water flood enhanced recovery schemes may not recover any secondary oil and perhaps some primary oil reserves could be lost by rapid encroachment of bottom water. Dome pointed out that operators in the north end of the Zama Field have installed more than double the number of injection points proposed in the "Board Staff Study".

(7) Views of Hudson's Bay

The two main indications of inter-reef interference, in the opinion of Hudson's Bay, are an initial pressure lower than anticipated and a similar pressure response to some influx or efflux of energy. The magnitude of interference effects can also be qualitatively assessed by reviewing the degree to which the pool's pressures have been influenced. Hudson's Bay cautioned that while strong divergence of pressure trends is indicative of isolated pools, a general similarity of pressure versus time plots is not a criterion for inter-reef interference. Such similarities also result if the reserves assigned to the pools for proration purposes are such that the production rate to actual pool reserve ratios are the same for all pools. Generally consistent bubble point pressures in a locality can also cause pools to have similar pressure performances.

Using the above guidelines, Hudson's Bay analysed (1) the pressure performance in its area of operation which is near the centre of the basin. Plots of pressure versus time for wells within each of fifteen areal groupings were presented. From the analysis of pressure performance it concluded that five of the areas exhibited limited, if any, inter-reef interference, five showed some evidence of interference and two were being adequately pressure maintained by either gas expansion or water influx. The other three areas have or will have water flood schemes installed. On this basis Hudson's Bay concluded that the Board staff's contention of good general communication throughout the Zama basin cannot be justified in Hudson's Bay's area of operation, but that localized regions of limited interference do exist.

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(1) Hudson's Bay submission contained a report, "Analysis and Review of Some Aspects of Interference Water Flooding in the Zama-Virgo Basin - June 1972", Hudson's Bay Oil and Gas Company Limited.

Hudson's Bay claimed there have been a substantial number of failures in water flood pressure maintenance schemes in the Zama basin because of a lack of inter-reef communication and abrupt increases in water-oil ratios in producing wells in the pressure maintained pools. It stated that group water flood projects could be successful in regions displaying strong evidence of communication, and such regions within its area of operation have been defined. However it would not consider installing schemes in these areas until further investigations were carried out regarding productivity, degree of pressure communication, ultimate recovery and injection water supply. Hudson's Bay considered it prudent to obtain further information from existing schemes to ensure that significant improvements could be made to productivity and ultimate recovery. Performance to date of presently operating interference water floods had not demonstrated that incremental gains over primary depletion could be achieved definitely by that means of pressure maintenance.

Hudson's Bay stated that Gulf's inner-outer reef concept may have a great deal of merit in explaining water production problems in the Zama basin.

(8) Views of Imperial

Imperial stated that, based on performance of its I.S. No. 4 during the first year of operation, a much lower degree of inter-reef communication was demonstrated than was previously anticipated. It concluded that similarities in pool pressure histories, the original means used to interpret inter-reef transmissibility, do not necessarily indicate adequate inter-reef communication. If Imperial could initiate the scheme over again, it would do so but some of the injectors would be different. Imperial agreed there were other pools outside the scheme which have indicated pressure response from I.S. No. 4 injection wells. Imperial considered Gulf's inner-outer reef concept and pressure build-up phenomena to be a possible explanation of the performance of some of the pools in its scheme and that the indicated pressure response could actually be masked by this build-up phenomena.

Imperial stated it had no evidence to suggest that water injection would worsen water-oil ratio performance. Possible explanations of water production could be Gulf's inner-outer reef concept or aquifer effects, or various forms of stratification or variations in reef geometry, or all of these.

(9) Views of Skelly

Skelly stated that water-oil ratios would increase if Zama basin pools were pressure maintained by water injection and would also increase in relation to the degree of natural water influx.

(10) Views of Sun

Sun stated it would not take any further action towards pressure maintenance unless there was an allowable or economic incentive to do so. Since its pools could not produce the primary allowables at present, any incremental allowable attributable to water flooding would not be produced. Further, water flooding possibly could aggravate the water-oil ratio problem.

(11) Views of Texaco Canada

Texaco Canada stated that the majority of its pools are in an area where there is an absence of inter-pool communication and hence, simultaneous or cyclic schemes are the only practical methods for pressure maintenance of its pools. Such schemes are only suitable for pools with significant reserves and very thick pay sections. Most of Texaco Canada's pools, in which pressure maintenance by such methods are feasible, already have such schemes in operation.

Texaco Canada noted that performance of its cyclic injection schemes varied and considered it premature to predict the success of the schemes. Experience had shown that injection rates, and as a result pressure gradients around the injection point, must be kept as low as possible during the injection cycle to avoid excessive water production.

(12) Views of Other Operators

Amoco, Canadian Industrial and Petrofina commented only on their own pools.

(13) Views of the Board

The Board observes that the performance of pools in the Zama basin show considerable variation and conflicting conclusions are frequently drawn from the same production, pressure and reservoir data for a pool. Consequently the Board believes studies and interpretation of performance of the basin should be conducted on a general basis before considering individual pools or groups of pools.

All participants agreed that water production is a definite characteristic of the basin and is a significant problem. The Board is in agreement but is unable to ascribe any single cause for the observed performance. The Board believes that high production rates and reservoir rock properties are important contributing factors. The high production rates stem from the unrealistically large initial reserve assignments and also to some extent on the operating practice of producing at high daily rates for only part of the monthly allowable period. Completion problems, to a small degree, appear to also contribute to water production problems.

Respecting Gulf's inner-outer reef concept and relationship of well performance with its position in a reef, the Board investigated this aspect using the seismic information available from previous submissions on some 25 pools in the basin. The Board was unable to establish any acceptable relationship of directional orientation of a well's rock properties with its position in the reef structure or with a well's water-oil ratio performance. The Board concludes that Gulf's concept is not a fully satisfactory explanation for water-oil ratio production performance in the basin.

Gulf's correlation and resultant coning index attempted to relate water production tendencies to location of a well completion in a reef. The Board is concerned that, although Gulf obtains statistical relationships, the theoretical and physical significance of the coning index relationship is not rigorously followed. The Board observes that, for physical significance, the values of the constants A, B, C and D must be positive and D should be unity. In many of the examples presented by Gulf the constants and the coning index were negative. The Board is not sure the relationship is any better than that provided by any high order polynomial equation. None the less, accepting Gulf's method as an empirical correlation, the Board considers that it may provide one means of judging a pool's water flood potential.

The Board agrees with the observations that little evidence of excess gas producing has been noted in the basin. Excess gas production is a normal expectation when the reservoir pressure of a pool becomes less than the saturation pressure resulting in segregation of the reservoir fluids. The Board does not accept Gulf's view that for almost all pools the bulk of the effective oil in place is still at a pressure greater than the bubble point. The Board believes that where pool pressures are generally below the bubble point, some excess gas exists in the reservoir. The Board expects that, when the critical gas saturation is reached in a pool, as must already have occurred in a number of low pressure pools, gas percolates to the top of the structure and does not move to the well bore region because of the presence of adequate vertical permeability. The Board accepts that further experience is necessary to positively determine the Zama basin production mechanisms.

The Board is satisfied that pressure performance of a significant number of pools in both primary and existing water flood schemes indicates insufficient communication to attempt a basin-wide pressure maintenance scheme. However, the pressure response obtained from schemes such as Dome's pilot and Imperial's I.S. No. 4 indicates that with planning and analysis of local areas groups of pools can be pressure maintained. In many cases, such a group of pools will encompass more than one owner and would necessitate some agreements before an enhanced recovery scheme could be started. The Board is encouraged by the results of schemes where operators have been able to agree on a method of sharing facilities, costs and production.

The Board acknowledges the concern expressed as to whether pressure maintenance will in fact provide additional recoverable reserves or may even reduce recovery. Many submissions contended that water-oil ratios had increased as a direct result of pressure maintenance schemes. The Board observes this to be true in some cyclic schemes and that it probably occurred in the Zama Keg River Z Pool, a scheme in a two well pool. Otherwise, there was no consistent evidence that water production is aggravated by the injection of water to pressure maintain pools in the basin. Performance under water flood does not appear to the Board to be adverse relative to primary depletion performance. Water-oil ratio trends established under primary production do not, in the Board's opinion, show any discernible change upon pressure response occurring as a result of water injection.

The Board currently includes minimum pressure requirements in most approvals for pressure maintenance by water injection in the Zama basin as a basis for determining the adequacy of injection. There have been some problems in administering these requirements because of the delays in expected pressure response in the integrated schemes. However, the Board believes it is a reasonable means of judging the response at a pool and that the practice should be continued.

THE ECONOMIC FEASIBILITY OF PRESSURE MAINTENANCE

(1) Views of Board Staff

The Board staff stated that single pool pressure maintenance schemes are generally economically unattractive. The exception to this would be pools with large reserves and thick pay sections, and those pools having more than one well.

The Board staff's submission included graphical representations of actual oil production and per cent of allowable produced for the two years, 1970 and 1971, for the Zama and Virgo Fields. Based on this information plus a histogram of production data which indicated that a large number of the wells in the basin were produced only for portions of the month, the Board staff contended that excess productive capacity existed in the basin. It estimated 75 per cent of the forecasted incremental water flood allowable could be produced for approximately two years with an estimated 10 per cent decline in productive capacity in each of the following two years. An economic analysis showed approximately a three year payout period for the Board staff's proposed basin-wide pressure maintenance scheme using 25 to 30 injection wells.

The Board staff estimated that gross revenue after royalty, as a result of the additional 62 million stock tank barrels of oil recovery attributed to water flooding the basin, would be 119 million dollars.

The economic analysis assumed common ownership for the entire scheme. This was considered important in minimizing costs.

(2) Views of Gulf

Gulf objected to the Board staff proposal contending that the scheme would not provide economic enhanced conservation of oil in the Zama basin. The necessary capital investment was considered by Gulf to be too large in relation to the recovery of the additional oil which may be lost through shrinkage. In a basin-wide pressure maintenance scheme many wells would prematurely reach the limiting economic water-oil ratio. Economic conservation could be better accomplished by water flooding only the pools from which significant gains in recovery could be reasonably expected.

(3) Views of Canadian Superior

Canadian Superior emphasized that many cases exist in the basin where pressure maintenance would not come close to being economically feasible. Based on the performance of pools with water flood schemes now in operation, pressure maintenance by water injection involved significant capital risk and may not result in improved recovery in the basin.

Canadian Superior considered the Board staff's conclusion that the basin could produce 75 per cent of the water flood allowable increment to be optimistic and therefore, the Board staff's economic analysis would also be optimistic. Canadian Superior claimed that increased production rates could result in premature water production and probable loss in ultimate reserves. In considering trends in water production, Canadian Superior doubted that the level of production predicted by the Board staff would be attained.

Canadian Superior also commented on the effects of the diverse ownership aspects in the basin. Under an overall integrated water flood program, the equitable distribution of capital expenditures and operating costs could be complex and particularly so in the event that pressure response was not evident, or unfavorable performance was experienced in participating pools.

(4) Views of Chevron

Chevron stated that from data on its own cyclic schemes, and others it has information on, there was no indication yet that any would result in an incremental economic recovery. Most of these schemes are considered by Chevron to be economic failures.

Chevron said that, based on past performance, pools with two wells may be economically successful but the current high failure rate of present pressure maintenance projects make any such ventures financially unattractive. There may be some areas which would respond to an area-wide pressure maintenance scheme but such a scheme would be considered very risky.

(5) Views of Dome

Due to the lack of surplus oil producing capacity in its area Dome considered that, for economic reasons, it was much nearer a good production practice situation than to a full-scale water flood enhanced recovery project. It concluded that although some interesting pressure responses had been observed, the extremely high water cuts and general lack of improvement in oil productivity made the feasibility of enhanced recovery by water flooding a questionable economic proposition.

(6) Views of Hudson's Bay

Hudson's Bay stated that it may be economically feasible to water flood single well pools, if some sort of cyclic scheme was technically feasible. If the reef was large enough then the drilling of a second well might be justified, provided no interference with another pool had been established. It also stated that it may be necessary to accept that pressure maintenance may not be practical in the Zama area.

Hudson's Bay considered the Board staff's contention that there is substantial excess productive capacity available to be totally misleading, since a large number of wells produce for only a few days per month. It performed an "excess capacity evaluation" on the Hudson's Bay area and concluded that most of the apparent excess productivity which would be utilized to meet enhanced recovery allowables is centered in only a few wells and the economic success of such a scheme would therefore be sensitive to water-oil ratios of a few pools. Many pools have extremely low allowables due to limited reserves which lead Hudson's Bay to anticipate rapidly declining future productivity if the pools were produced at current capacity levels. Further, the degree of excess productivity available is so distributed that embarking on a basin-wide scheme at such a risk level would require a very high rate of return.

(7) Views of Imperial

Imperial stated that the Board staff's proposed basin-wide scheme would not likely be technically nor eonomically feasible. Because only a limited number of wells appear to respond to any one injector, the number of injection wells proposed by the Board staff would only be one-third to one-fifth of the number that Imperial considered would be required for implementation of such a scheme. Therefore, the proposed scheme would become economically impractical due to the cost of these extra injectors.

Imperial stated that since several pools outside the area of its I.S. No. 4 scheme area appeared to have shown pressure response, a number of well groups could be pressure maintained successfully if the problems of choosing the right injector and predetermining the communication group could be resolved. With respect to the diverse ownership problem, Imperial contended that the owners should be left to work out ownership and operating problems among themselves.

(8) Views of Sun

Sun contended there was no economic incentive to proceed with pressure maintenance in its primary producing pools at this time because its pools could not likely produce any incremental increase in allowable. Of the four pools which could be considered as water flood candidates from a technical stand point, the economic feasibility of including them in an area-wide co-operative scheme would be doubtful.

(9) Views of Texaco Canada

Based on its knowledge of the lack of communication between producing pools and water injection wells, Texaco Canada stated that the incremental economic analysis presented by the Board staff based on 25 injectors may be optimistic. Because of the varied performance of the cyclic schemes Texaco Canada operates, such schemes may be economically successful in some pools if operated correctly but it would be premature to predict success.

(10) Views of Other Operators

Amoco, Ashland, Canadian Industrial, Petrofina and Skelly had views only on their individual pool or pools.

(11) Views of the Board

Having regard for the evidence presented at the hearing, the Board concludes that the inter-reef communication throughout the basin is such that the number of injection well locations used in the Board's staff proposed basin-wide scheme is insufficient. Doubling the number of injectors would be a minimal requirement for assuring technical success but this would make the proposed scheme economically impracticable.

None the less, the Board believes that there is a need for pressure maintenance in the Zama basin. As discussed in the previous section, the Board believes that while there may be some question as to the correct absolute pressures, there is little doubt that the pressures have fallen significantly and, in the absence of pressure maintenance, generally will continue to decline. The Board is concerned that if remedial action is deferred until gas-oil ratios have increased significantly or productivity is seriously reduced, there may be a significant loss in oil recovery. While those appearing at the hearing did not present an alternative proposal to the Board staff proposal, most operators indicated that they would keep their pools under surveillance and would implement enhanced recovery operations when such was considered desirable.

The Board believes that the best prospect for enhanced recovery operations relate to those areas of the basin where there is good inter-reef communication, thereby making group type pressure maintenance schemes technically and economically feasible. While it believes that group type schemes hold the most promise the Board is of the opinion that cyclic production-injection schemes and simultaneous production-injection schemes in single well pools may also be feasible under favorable conditions such as isolated pools, large reserves and low pool pressures. Multi-well pools offer somewhat more flexibility than do single well pools, both technically and economically, as prospects for enhanced recovery operations.

The Board recognizes that the unique characteristics of the Zama basin not only increase the risks of implementing enhanced recovery operations but also make it difficult to unitize or agree on co-operative operations. Furthermore, current allowable regulations inhibit operators from undertaking interference tests to identify pools that are in effective communication thus making it difficult to develop group schemes. In order to remedy this deficiency and thereby assist enhanced recovery operations, the Board believes that it would be desirable to permit additional flexibility in the overproduction and underproduction regulations for spread tests. Following identification of the pools that are in common communication integrated schemes could then be initiated. Where pools in communication have different ownership it would be necessary to establish co-operative injection schemes as has occurred elsewhere in the Province.

Several submissions raised the question of productive capacity in the basin as an important economic consideration. The Board accepts that the Board staff estimates of available excess productivity capacity may be somewhat optimistic for the basin, but it does not agree fully with Hudson's Bay that the extra productive capacity is in only a few pools. Hudson's Bay, while questioning the Board staff estimates, did not provide its estimates of productive capacity except for very limited areas of the basin. With allowables currently increasing, the Board recognizes that the excess capacity increment is diminishing and the allowable incentive normally associated with enhanced recovery is decreasing.

The Board believes operators in the Zama basin should continue to assess the means and feasibility of implementing enhanced recovery operations. For its part the Board intends to continue to review pool pressures and performance. Where it appears warranted the Board should require studies respecting the feasibility of enhanced recovery operations.

THE BOARD'S FINDINGS

(1) There is a significant decline in reservoir pressures in most of the pools in the Zama basin. Although the measured pressures may give a pessimistic value of the absolute level of pool pressures, the relative pressures being taken in the basin give a general indication of what actually is occurring. The decline in pressures is evidence of the need for pressure maintenance in the basin.

(2) Communication among pools as indicated by initial pressures and pressure response from water injection is statistically well established. The degree of communication appears to be insufficient to meet the economic feasibility requirements of a basin-wide pressure maintenance scheme. A basin-wide scheme such as that proposed by the Board staff appears to be neither technically nor economically feasible.

(3) There is no conclusive evidence that water production in the basin has been aggravated as a direct result of pressure maintenance by water injection, except for a few special cases.

(4) There are many localized areas of good inter-reef communication where group-type pressure maintenance schemes appear to be both technically and economically feasible. Pool groups in these areas should be identified and studied in the immediate future with the objective of initiating pressure maintenance.

(5) The risks involved in initiating pressure maintenance schemes in the Zama basin area are high and the diversity of ownership creates additional problems, but the volumes of oil reserves estimated to be recoverable from the basin by enhanced recovery are large enough to warrant pool by pool study of the feasibility of pressure maintenance.

(6) Operators in the Zama basin should maintain close surveillance of pool performance and extend their studies to determine the feasibility of pressure maintenance in their respective pools.

(7) Multi-pool pilot injection schemes may be needed to determine those pools that are in pressure communication and hence suitable for inclusion in an integrated scheme. The overproduction and underproduction regulations should provide increased flexibility for such tests.

(8) Gulf's proposal to reduce the frequency of pressure surveys should be dismissed at this time. Pressure surveys should continue in accordance with the current requirements.

(9) The use of minimum pressure clauses in pressure maintenance approvals should be continued as a means of ensuring satisfactory pressure performance of schemes.

DECISION

1. The Board staff's proposal for a basin-wide pressure maintenance scheme by water injection in the Zama basin is dismissed.

2. The Board considers that it is feasible to maintain pressure by water injection in parts of the Zama basin, particularly in those groups of pools where pressure communication is

indicated. The Board may require detailed pressure maintenance feasibility studies from the owners of some areas or groups of pools considered to be in pressure communication.

3. The Board will permit increased flexibility within the overproduction and underproduction regulations where a pilot fluid injection test is conducted for the purpose of identifying groups of pools that are in pressure communication. Details of the procedures are provided in IL-OG 73-1 being issued concurrently with this Decision.

4. The Board will continue to require pressure surveys to be taken in accordance with section 11.102 of the Oil and Gas Conservation Regulations as amended July 1972.

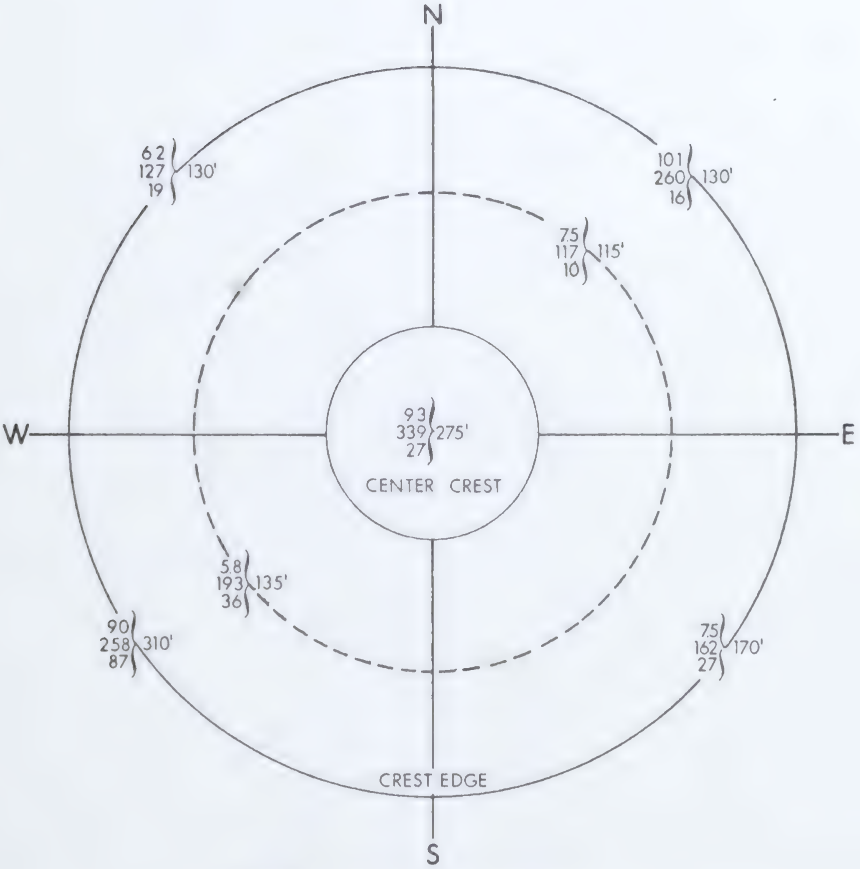
ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
January 9, 1973.

ZAMA BASIN
(ZAMA MEMBER ONLY)
FIGURE 1 to DECISION 73-1

SCHEMATIC COMPOSITE MAP OF RESERVOIR ROCK PROPERTIES OF ZAMA MEMBER BASED ON CORE ANALYSIS DATA & SEISMIC INFORMATION ON 25 WELLS



LEGEND

6.5 } 300 — POROSITY % } APPROXIMATE FOOTAGE
100 — HORIZONTAL PERMEABILITY md
60 — VERTICAL PERMEABILITY md

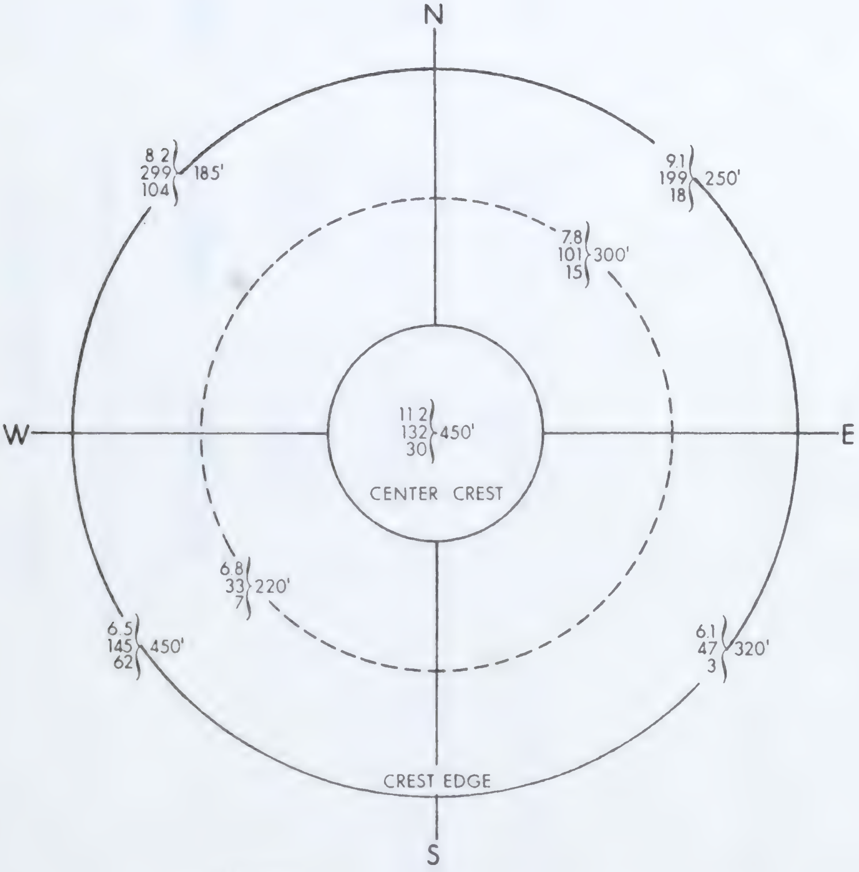
NOTE: Footage Weighted Averages

ZAMA BASIN

(KEG RIVER ONLY)

FIGURE 2 to DECISION 73-1

SCHEMATIC COMPOSITE MAP OF RESERVOIR ROCK PROPERTIES OF KEG RIVER BASED ON CORE ANALYSIS DATA & SEISMIC INFORMATION ON 25 WELLS



LEGEND

6.5 POROSITY %

100 300 HORIZONTAL PERMEABILITY md — APPROXIMATE FOOTAGE

60 VERTICAL PERMEABILITY md

NOTE Footage Weighted Averages

ENERGY RESOURCES CONSERVATION BOARD

TABLE 1 to DECISION 73-1

ZAMA BASIN CORE DATA SUMMARY

	Zama Member	Keg River (Oil)	Keg River (Aquifer)	Total
Footage	6,009	5,183	1,860	13,052
Porosity-Footage	45,577	37,066	13,324	95,967
Porosity (%)	7.59	7.15	7.16	7.35
Footage	5,692	4,732	1,702	12,126
Horizontal Permeability-Footage	1,730,313	495,163	234,337	2,459,813
Horizontal Permeability (md)	304	105	138	203
Footage	5,572	4,514	1,616	11,702
Vertical Permeability-Footage	226,312	197,865	83,254	507,434
Vertical Permeability (md)	40.6	43.8	51.5	43.4

Cut-Offs

.01 md $<$ Horizontal Permeability $<$ 6000 md

APPENDIX A

Decision 73-1 - Proceeding No. 6272
Empirical Water Production Correlation

Gulf submitted the following generalized equation relating cumulative water-oil ratio to both cumulative oil production and time.

$$WOR = e^{y} - D$$

where $y = A \sum qi + B \sum \left[qi^{2}/q_{1} \right] + C \sum \left[(qi/q_{1})^{2} \, (qav - q_{1}) \right]$

A, B, C and D are constants for a given well in a correlation segment. Gulf defined "Coning Index" = A + B + C

q_1 = monthly oil production rate in the first month that water production is reported in a correlation segment

qav = average monthly oil production since the beginning of water production in the correlation segment

$\sum qi$ = summation of the monthly oil production rates for a correlation segment

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-2
Application No. 6471

EXEMPTION FROM SULPHUR RECOVERY GUIDELINES
CROSSFIELD GAS PROCESSING PLANT

THE APPLICATION AND HEARING

Petrogas Processing Ltd. applied under section 38, subsection (1), clause (b) of The Oil and Gas Conservation Act for an amendment of Board Approval No. 1477 and for exemption of the Crossfield Gas Processing Plant from the sulphur recovery efficiency guidelines prescribed in Board Informational Letter No. IL 71-29.

The application was heard on August 29, 1972, by the Energy Resources Conservation Board with G. W. Govier, P. Eng., and D. R. Craig, P. Eng., sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Petrogas Processing Ltd.	H.B. Shelton	Petrogas
	R.S. Blackett, P. Eng.	
	W.W. Chalmers	
	K.A. Charters, P. Eng.	
	L.C. Cole, P. Eng.	
	R.S. Geddes, P. Eng.	
	J.A. Richardson, P. Eng.	(of Barry and Richardson)
	J. Lukacs, P. Eng.	(of Western Research and Development Ltd.)
	R.P. Rankine	(of Western Research and Development Ltd.)
	C.L. Sibbald	(of the Sibbald Group)
	R.K. Agrawal, P. Eng.	(of Intercomp Resource Development and Engineering Ltd.)
Board Staff	L.A. Mazurek, P. Eng.	
	R.B. Dunbar, P. Eng.	

There were no interventions respecting the application.

BACKGROUND

Prior to the issuance of Board Approval No. 1477 on March 1, 1971, the Crossfield Plant of Petrogas was operated under Board Approval 843, issued April 1, 1966, and Provincial Board of Health Interim Air Pollution Approval No. 1092-P-265, dated November 13, 1969. The interim air pollution approval amended Final Air Pollution Approval No. 225-P-265, dated March 15, 1966. Board Approval No. 843 required a minimum sulphur recovery efficiency of 97 per cent.

By a previous application to the Board dated October 20, 1970, (Application No. 5383) Petrogas applied for amendment of Board Approval No. 843 to require a minimum sulphur recovery efficiency of 95 per cent and an increase in allowable sulphur dioxide emission rates. The Board granted that part of the application requesting a reduced sulphur recovery efficiency for an interim period, subject to the conditions now contained in Approval No. 1477 which permits the Crossfield Plant to process a maximum equivalent sulphur inlet rate of 1925 long tons per day and requires the recovery in the form of elemental sulphur of,

(i) from January 1, 1972 to December 31, 1973, not less than 96 per cent of the sulphur contained in the gas delivered to the plant, and

(ii) after December 31, 1973, in the range 97 to 99 per cent, to be determined by the Board following receipt of a submission by the operator, respecting the specific sulphur recovery efficiency to be required.

This decision was issued on February 18, 1971.

On November 9, 1971 the Board issued Informational Letter No. IL 71-29 which prescribes sulphur recovery requirements for gas processing operations. The guidelines are related to plant size and various acid gas qualities. The plant size categories were determined, having regard for relative economics, practicality and operating flexibility. The Board stated that existing plants should be upgraded in accordance with the guidelines wherever practicable and that all plants should meet the standards as soon as possible but not later than December 31, 1974. The Board recognized that upgrading may not be justified for certain older plants and provided for applications for exemption from the prescribed recovery levels, or for lesser adjustments, where exceptional circumstances exist.

For the subject facility Informational Letter No. IL 71-29 specifies that a plant, with a sulphur inlet rate of between 1000 to 4000 long tons per day of sulphur and processing favourable quality acid gas, recover 98 to 99 per cent of the sulphur delivered to the plant after December 31, 1974. Petrogas requests that Approval No. 1477 be amended to require a sulphur recovery of 97 per cent after December 31, 1973 and a maximum equivalent sulphur inlet rate of 1700 long tons per day.

DEFINITION OF ISSUE

The main issue of the application is the future sulphur recovery efficiency to be required of the subject plant. Approval No. 1477 requires a recovery in the range 97 to 99 per cent after December 31, 1973 while Informational Letter No. IL 71-29 requires a recovery in the range 98 to 99 per cent after December 31, 1974. Petrogas requests that the required recovery be set at 97 per cent, outside the range required by the sulphur recovery guidelines. The Board, by approximate interpolation based on a maximum inlet capacity of 1700 long tons per day, interprets the guidelines to require a recovery of 98 per cent and considers the application to be one for exemption from this level. The issue therefore reduces to whether the required recovery, to apply after December 31, 1974, should be 97 or 98 per cent, or some intermediate percentage. At the maximum sulphur inlet rate of 1700 long tons per day, the sulphur dioxide emission rate would be 102 long tons per day at 97 per cent sulphur recovery efficiency or 68 long tons per day at 98 per cent sulphur recovery efficiency.

SUBMISSION OF THE APPLICANT

Petrogas submitted that it should be granted exemption from the guideline requirements basing its claim on the economic, technical and environmental aspects of the plant operation.

It stated that the plant has been in operation almost eleven years and is therefore an 'older' plant and as such would require substantial upgrading to meet a 98 per cent or better sulphur recovery efficiency.

The company indicated that it is planning to spend an additional some $6,400,000 over the next 20 years to upgrade the efficiency of the existing Claus units to a 97 per cent level. Petrogas stated that, in its opinion, further costs would be unreasonable and unacceptable and would likely never be economically justifiable.

Petrogas presented evaluations of several alternatives to meet the guideline requirements. It estimated that building a tail gas clean-up plant designed for the maximum sulphur inlet rate and to maintain a sulphur recovery of 98.2 per cent would cost a further $13,400,000 in capital and operating costs over 16 years from 1974 to 1991.

Petrogas stated that field gas production is expected to start to decline below the requested inlet capacity of 45.3 MMcfd of hydrogen sulphide in 1975, thus progressively reducing the amount of raw gas available for processing and the rate of sulphur dioxide emissions compared to present levels. Petrogas stated that at optimum production rates the average sulphur inlet rate would decline to less than 1000 long tons per day by 1980.

To further support its application Petrogas stated that tail gas clean-up should not be required at this time since research on the fundamental Claus process with respect to improvement in sulphur recovery efficiencies has been particularly rewarding during recent years. Further investigation in this direction is warranted and further improvements with time should be expected. Petrogas submitted operating data indicating short term recoveries approaching 98 per cent with the existing facilities. Petrogas stated that with catalyst changes once every four months average recovery levels of 97.3 per cent could probably be maintained with the existing facilities.

Petrogas described its current program for further improvements to the Claus process - one with emphasis in the areas of reaction furnace and burner design, catalyst performance, and reduction in the hydrocarbon content of the acid gas. Petrogas stated that, even if the ultimate recovery efficiency requires tail gas clean-up, economics would favour achieving the best possible efficiency in the Claus portion of the plant.

Petrogas stated that extensive air quality monitoring conducted to date has not indicated the need for reduction in sulphur dioxide emission rate. The Provincial Ambient Air Quality Standard of 0.30 parts per million of sulphur dioxide (averaged over a one-hour period) has been met more than 99.96 per cent of the time at the monitoring locations. Furthermore, measured ambient air sulphur dioxide concentrations have been below a 15-minute average concentration of 0.15 parts per million almost 99.7 per cent of the time.

An air quality study submitted by Petrogas dealt with atmospheric conditions and plant variables considered to be associated with measureable ground level concentrations of sulphur dioxide in the plant area. Petrogas concluded from the report that the breakup of atmospheric temperature inversions by heating of the ground surface is a significant meteorological factor responsible for sporadic excessive ground level sulphur dioxide concentrations in the area. Petrogas stated that these conditions were beyond the control of the plant operator and that present technology does not make it feasible to control plant operations to prevent such occassional occurrences.

Petrogas submitted studies of atmospheric corrosion rates which in its view indicate that higher recovery is not required to reduce atmospheric corrosion. Petrogas stated that the most severe corrosion rates recorded close to the plant were only slightly greater than the rates recorded at the background stations east of Strathmore and are approximately the same as at reference stations in Calgary and the Lacombe Agriculture Experimental Station.

Petrogas also submitted a report of crop and soil conditions in a 30-square mile area surrounding the plant. The few problem areas discovered appear to be related principally to natural conditions and to well site or plant operations other than the operation of the sulphur recovery plants and incinerator stacks.

Petrogas further stated that in its view relationships with residents of the community in which it operates are excellent. Petrogas stated it had received a minimal number of complaints regarding air quality and all such complaints had been promptly and thoroughly investigated. Petrogas stated that the Department of the Environment has commended it on "responsible plant operation" which has resulted in atmospheric sulphur dioxide and hydrogen sulphide levels considerably below the Alberta Ambient Air Quality Standards.

VIEWS OF THE BOARD

The Board has considered the arguments submitted by Petrogas regarding the technical, environmental and economic aspects of the plant operation and the relationship of these factors to the application of the sulphur recovery efficiency guidelines to the Crossfield Plant.

With regard to the technical aspects of sulphur recovery at the plant, the Board accepts that Petrogas has demonstrated that the existing facilities are capable of sustaining a 97 per cent recovery level. The Board believes that somewhat higher levels could be achieved with further modifications to the plant procedures and facilities such as more frequent catalyst replacement, advances in Claus catalyst technology and further optimization of the plant. The Board is of the view however that, with present Claus technology, a sustained recovery of 98 per cent could only be achieved through installation of tail gas sulphur recovery facilities. The Board believes that such facilities have been demonstrated to be technically feasible elsewhere and should be so in the subject instance. It recognizes however that some problems will probably be encountered with the early operation of some of the first installations.

The Board accepts the studies submitted by Petrogas regarding monitored air quality, atmospheric corrosion rates and crop and soil conditions in the vicinity of the plant as a satisfactory indication that to date, local environmental damage due to emissions from the plant incinerator stack has not occurred. Monitoring has indicated commendable operations with respect to Provincial Air Quality Standards, and the lack of recent complaints indicates that the plant operation has been satisfactory with respect to protection of the local environment.

Notwithstanding the indicated satisfactory operation respecting local environmental protection, a satisfactory complaint history and compliance with the Provincial Air Quality Standards, the Board intends the minimum sulphur recovery efficiency guidelines to be an overall control of plant operations beyond, and essentially independent of, local environmental protection. The Board expects that plant operations would be conducted so as to have no unacceptable detrimental impact on the local environment, to satisfy Provincial Ambient Air Quality Standards and to result in a minimum of complaints, quite apart from the requirements of the sulphur recovery efficiency guidelines. The Board believes that, even though by present ground level standards the environmental aspects of a plant operation might be satisfactory, maximum practical sulphur recovery should be achieved both in the interests of conservation of a natural resource and to minimize overall sulphur dioxide emissions and the potential for adverse environmental effects on a broad scale. The sulphur recovery guidelines are designed to provide for a sulphur recovery level that is as high as is practical having regard for both economics and sulphur recovery technology.

Provided the local environmental aspects of a plant operation are satisfactory and considering that for normal cases the industry is treating sulphur as a by-product, the Board believes that, in general, the sulphur recovery should be at the level which would give a discounted rate of return in the range of seven to ten per cent on the total undepreciated investment attributed to the total sulphur recovery facilities evaluated as at January 1, 1975. Under present conditions any higher levels of profitability of sour gas processing must be maintained through prices of recovered hydrocarbons. In special cases, where income from sulphur sales is a significant portion of overall plant income and sulphur cannot be considered a by-product, the Board, before ruling on an application, may consider the overall economics of an entire operation including costs and revenue related to the recovery and sale of residue gas and natural gas liquids. In deciding individual cases within the rate of return range of seven to ten per cent before income tax the Board would have regard for the nature of the development in the general plant area and other general matters.

The Board has examined the economics of the operation of the sulphur recovery facility at the subject plant to determine the discounted rate of return after 1974. The Board calculated that approximately $200,000 of past sulphur plant investment should be carried forward to January 1, 1975 as "unrecovered" investment for the existing facility. This calculation was based on paying out the existing equipment by allowing a ten per cent per year straight line depreciation subject to available cash flow. The Board estimated that an investment of approximately $3,100,000 would be required to increase the sulphur recovery to 98 per cent. This is somewhat lower than the Petrogas estimate of $3,470,000. The Board's economic analysis was based on an investment of $3,300,000 accounting for new capital and "unrecovered" past investment. The Board used both "low" and "high" estimates of sulphur plant operating costs due to the uncertainty of costs respecting tail gas clean-up. The Board's costs were escalated three per cent per year with adjustment for decrease in costs as production declines. The Board estimated total sulphur plant operating costs from 1975 to 1992 to be from $19,200,000 to $21,800,000 compared to the Petrogas estimate of approximately $29,200,000. The Board based its analysis on its own forecast of sulphur sales and sulphur prices and used the applicant's forecast of sulphur production. The data used in the Board's economic evaluation is given on Table 1.

The Board's estimate of operating costs is somewhat lower than that submitted by the applicant partly due to the Board's forecast decline in operating costs as production declines. However, the Board has based its estimate on all data available to it and considers it to be reasonable. The Board notes that its estimate of revenue derived from sulphur sales is not as optimistic as that submitted by the applicant.

The economic evaluation was carried out using illustrative royalty rates from 16.67 to 25 per cent and using both the "low" and "high" estimates of operating costs. This analysis indicated a rate of return before taxes of from 27 to 21 per cent on the overall sulphur recovery plant operation.

The Board carried out further economic evaluations using a more conservative sulphur price and sulphur sales forecast which resulted in calculated rates of return of the order of 13 per cent. The Board notes that the applicant's evaluation of the overall sulphur plant economics also indicates a favourable return on future operations even with the installation of tail gas clean-up facilities.

The Board concludes that additional sulphur recovery is desirable and that, although increasing the sulphur recovery to 98 per cent would increase the cost of operations substantially, the sulphur recovery operation would remain modestly profitable and the cost of additional sulphur recovery is justified to reduce total sulphur dioxide emissions and increase conservation of a natural resource.

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-3
Application No. 6645

TRANSMISSION LINE - WABAMUN TO STONY PLAIN

INTRODUCTION

Calgary Power Ltd. applied under The Hydro and Electric Energy Act for a permit to construct a transmission line, an order to connect it and a licence to operate it. The transmission line would run from the applicant's Wabamun power plant to a pump station of Trans Mountain Oil Pipe Line Company about one mile north of Stony Plain.

Objections having been filed affecting the most easterly five miles, more or less, of the proposed transmission line, a hearing to consider that portion of the application was held at Edmonton on January 8, 1973, by the Board with Vernon Millard and J. I. Strong, P. Eng., sitting.

The following appeared, or were represented, at the hearing:

	Represented by	Witnesses
Calgary Power Ltd.	R. J. Pitt	E. J. Macleod, P.Eng. L. Murgatroyd, P.Eng. Bert Vik
R. Darimont	H. B. Madill	
John D. Fuhr	John D. Fuhr	John D. Fuhr
J. Tyminsky	J. Tyminsky	J. Tyminsky
Board Staff	N. A. Macleod, Q.C. C. J. Goodman, P.Eng.	

THE BACKGROUND TO THE APPLICATION AND THE APPLICATION

The purpose of the proposed transmission line is to deliver electric energy generated at the applicant's Wabamun plant to a pump station of Trans Mountain Oil Pipe Line Company north of Stony Plain.

It is the policy of the Board to publish notice of an application for a permit to construct a transmission line for which the applicant has not acquired the right of way.

On November 15, 1972 the Board published notice of the subject application. Objections were filed by or on behalf of four persons who reside along the easterly half of the route of the proposed transmission line.

On December 12, 1972 the Board published notice of the subject hearing, and interventions were filed on behalf of John D. Fuhr and Raymond Darimont. Mr. John Tyminsky appeared at the hearing to give evidence and was accepted as an intervener.

Inasmuch as no objections were received by the Board respecting the western portion of the proposed route, the Board issued on January 11, 1973 a permit for that part of the proposed transmission line terminating at a point in the South-west quarter of Section 11, Township 53, Range 3, West of the 5th Meridian.

DEFINITION OF ISSUES

(1) The need for the transmission line and whether it will serve the public interest.

(2) The location of the transmission line as it affects the interests of the utility company, the interests of the land owners and the public interest.

THE NEED FOR THE TRANSMISSION LINE

(1) Views of the Applicant

The applicant's submission stated that a 138 K.V. transmission line is required to supply a new 3,000 horse power pump station of Trans Mountain Pipe Line located about one mile north of Stony Plain. The applicant also stated that the proposed 138 K.V. transmission line is needed to provide capacity necessary because of the rapid growth in electric energy requirements in the Stony Plain area, together with anticipated growth of energy requirements developing between Stony Plain and Edmonton within a year or two. While the applicant has an existing 69 K.V. transmission line from the Wabamun plant to its substation located at Spruce Grove between Edmonton and Stony Plain, that line is now operating near capacity with a load which is growing at a rate of 15 to 20 per cent annually. In the applicant's opinion this 69 K.V. line is inadequate to serve the pumping station in addition to the applicant's present customers in the area. Calgary Power also stated that Trans Mountain Pipe Line has requested service to be supplied by February 1, 1973.

(2) Views of the Interveners

None of the interveners expressed views on the need for the transmission line.

(3) Views of the Board

The Board is satisfied, by the evidence before it, that an additional transmission line from the Wabamun power plant to the Stony Plain area is essential to satisfy the area's increasing electric energy requirements, and that such an additional line is in the public interest. The evidence, in addition, has established that existing transmission line facilities are insufficient to provide the present and future electric energy requirements of the area. The Board also notes that the proposed area in which the transmission line is to be located, lying between Wabamun and the City of Edmonton, is within Calgary Power's existing service area.

THE LOCATION OF THE TRANSMISSION LINE

(1) Views of the Applicant

The applicant stated that the transmission line would be of single pole construction 60 to 65 feet in height with normal span length between poles of 500 to 550 feet. The poles and cross arms would carry three conductor wires plus one overhead lightning protection wire. In two locations, where it is necessary to overbuild a rural electrification line, it would carry an additional line and eliminate the rural electrification system poles.

The applicant stated that the route of the transmission line was determined by the location of the Trans Mountain pump station service situated approximately 20 miles due east of the Wabamun Power plant. Almost a direct line is obtained by using a portion of Calgary Power's existing transmission line right of way between Wabamun and Section 11, Township 53, Range 3, West of the 5th Meridian and by then following the blind line east with minor deviations between the West half of Sections 11 and 2, Township 53, Range 3, West of the 5th Meridian to the Trans Mountain pump station immediately North of the blind line in Section 12, Township 53, Range 1, West of the 5th Meridian. The applicant stated that in using the blind line the total width of right of way of 40 feet would involve acquiring 20 feet of right of way from the properties on either side of the blind line. The line would be located 2 feet to the north or south of the blind line as the case may be. This would result in actual pole construction on one side of the line and the overhang of wires and cross arms on both sides of the blind line. The application submitted by Calgary Power included a plan of the proposed location showing where it has been unsuccessful in obtaining a right of way. At the hearing the applicant stated that in several cases agreement had been reached with the owners, subsequently to submitting the original application and that, apart from one change in the original route in Sections 7 and 8, Township 53, Range 2, West of the 5th Meridian to satisfy a land owner, the location of the transmission line on the north side of the blind line was suitable to all owners as far East as the East boundary of Sections 6 and 7, Township 53, Range 1, West of the 5th Meridian. Appendix 1, Sections A and B, shows the location agreed to at the time of the hearing.

The west boundary of Sections 5 and 8, Township 53, Range 1, West of the 5th Meridian shown on Appendix 1, Section C, intersects with Highway 16 at a small development known as Beach Corner. Calgary Power stated that if it had continued due east on the blind line, and crossed Highway 16, the location of the line would have involved acquisition of right of way at Beach Corner on properties accomodating a service station, a garage and two houses. To avoid these properties the applicant proposed to proceed parallel to and on the South side of Highway 16 and to return to the original blind line as shown on Appendix 1, Section C, by crossing the highway in a north-easterly direction. This route would avoid the Beach Corner properties except for overhang on one property. After returning to the blind line the route would continue due east to the East boundary of Section 5, Township 53, Range 1, West of the 5th Meridian with the poles located two feet South of the blind line. The applicant stated that it would have preferred to continue eastward on the same line through Section 4, but this route involved clearing trees around two houses located adjacent to the blind line in the North-west quarter of Section 4 and the South-west quarter of Section 9, Township 53, Range 1, West of the 5th Meridian. It also involved clearing brush and trees from the most southerly 20 feet of a 16-lot subdivision called Hubbles Lake in the South-east quarter of Section 9, Township 53, Range 1, West of the 5th Meridian. Calgary Power avoided this subdivision by proposing that the route leave the blind line in the North-east quarter of Section 5 and run diagonally to a point 280 feet south of the blind line in the adjoining North-west quarter of Section 4 then proceeding directly east through Section 4, Township 53, Range 1, West of the 5th Meridian. Calgary Power stated that it had obtained an option for this route from Mr. Darimont, the owner of the North-east quarter of Section 5, and the North-west quarter of Section 4, but that Mr. Darimont later objected to the location as unsatisfactory. Calgary Power also stated that they did not have an option from Mr. John Tyminsky, the owner of the North-east quarter of Section 4.

Calgary Power's original application shows the location of the line after leaving the North-east quarter of Section 4 returning to the blind line and extending eastward on the south side of the blind line through Sections 3, 2 and 1 to the point where it supplies the Trans Mountain service in the South-east quarter of Section 12, Township 53, Range 1, West of the 5th Meridian.

Calgary Power stated that they had not yet acquired an easement from J. Adams and R. Adams, the owners of the North-east quarter of Section 2 and the North-west quarter of Section 1, Township 53, Range 2, West of the 5th Meridian. The applicant decided to move the route to the north side of the blind line at the middle of Section 2 and then proceed east to the Trans Mountain property so that the easement required will be for overhang only and thereby avoiding the construction of any poles on the Adams' property.

In summary, the applant stated that the route chosen by it seemed to be the most reasonable. The applicant submitted that the greater part of the right of way had been acquired prior to the hearing. It claimed this indicated that the majority of the people located along the route felt it was a reasonable choice including the residents affected at Beach Corner where an easement had been obtained. The applicant also stated that, in areas of controversy, it had looked at various alternative proposals and had made an objective decision with regard to the selected route.

The applicant stated that an alternative route commencing from Beach Corner and paralleling highway 16 for a greater length had been considered for the eastern portion of the route. Calgary Power claimed that as well as the additional length at a cost of $15,000 per mile, there would be at least the same number of land owners to deal with. Consequently the selected route of following the blind line was considered the most satisfactory.

(2) Views of J. D. Fuhr

Mr. Fuhr objected to the location of the transmission line for two reasons; if located within a few feet of the east boundary of his property it would devalue his property and it would create interference with his radio and television reception and in particular interfere with the mobile radio unit used in connection with his business. Mr. Fuhr stated that his real estate agent, Mr. Harlton, said that a power line would devalue his property if the line was located in front of the house where it could be seen from the front windows.

Mr. Fuhr stated that he is not concerned about the location of an existing transmission line on the west side of his premises because he cannot see it from his home, but is concerned about the visual impact of the proposed line as it would be visible from his front windows.

Mr. Fuhr explained that in his opinion the location of the transmission line near the blind line on Sections 4 and 5 would interfere with the "line of sight" radio signal path between his home and his business in Spruce Grove. To avoid his radio signal path Mr. Fuhr suggested that the transmission line be located farther north on Sections 8 and 9 or alternatively it continue following Highway 16 further south before turning due east.

Mr. Fuhr claimed that the mobile radio unit in his truck is the unit most seriously affected and when located very near to a transmission line the noise level renders the unit inoperative.

(3) Views of J. Tyminsky

Mr. Tyminsky, as owner of the North-east quarter of Section 4, Township 53, Range 1, West of the 5th Meridian, objected to the transmission line being located approximately 280 feet south of the north boundary of his property. Mr. Tyminsky believed his land would be devalued in the event that he wished to subdivide it at some time in the future because the entire 40-foot right of way would be located on his property in such a way that it could interfere with the economic subdivision of his land. He stated that he would prefer it to be located along the blind line and would not object to a 20-foot allowance for half the right of way on his side of this line.

(4) Views of R. Darimont

Mr. Darimont, the owner of the North-east quarter of Section 5, Township 53, Range 1, West of the 5th Meridian and the North-west quarter of Section 4, Township 53, Range 1, West of the 5th Meridian, represented by Mr. Madill, submitted that he did not object to the transmission line following the blind line in the North-east quarter of Section 5, which would involve 20 feet of right of way south of the north boundary of his property, but did object to the jog south to the North-west quarter of Section 4, Township 53, Range 1, West of the 5th Meridian which would locate the transmission line 280 feet south of the north boundary of his property. Mr. Darimont also submitted that the presence of the transmission line 280 feet south of the north boundary of his property would have a detrimental affect on future development of the property and could create difficulties in plotting future parcels of land and locating the roads and improvements which would be necessary for such a development.

Mr. Madill reiterated the statement made in Mr. Darimont's submission that the detrimental elements would not exist to the same extent if the transmission line was to be located along the blind line at the north side of his property in the North-west quarter of Section 4, Township 53, Range 1, West of the 5th Meridian and that the interests of all parties would thereby be more fairly served. It was advocated, on behalf of Mr. Darimont, that if a permit was granted for the transmission line, the permit should be conditional on the line following the north boundary throughout Mr. Darimont's property.

(5) Views of other Interveners

In addition to the above submissions the Board received letters from two owners after the initial publication of notice.

Mr. Steve Wasylyshyn is owner of the South-west quarter, Section 9, Township 53, Range 2, West of the 5th Meridian and Mr. James R. Miller is owner of a part of the North-west quarter of Section 4, Township 53, Range 1, West of the 5th Meridian. Mr. Wasylyshyn stated in his submission that the proposed transmission line would be within 50 feet of his house, that he felt it would interfere with radio and television reception; that if the line were to fall it would be dangerous and that the cutting of trees on the right of way would reduce the shelter to the house that had existed since his father purchased the land. Mr. Wasylyshyn did not appear at the hearing. The information supplied by the applicant indicated that it had obtained an easement on his parcel of land.

Mr. James Miller expressed concern in his intervention that, if the transmission line passed over his buildings as originally shown, it would hamper future expansion to his buildings and that he did not want any trees cut down on the right of way. Mr. Miller did not appear at the hearing. The applicant stated that the route of the transmission line was altered to miss the property of Mr. Miller as shown on Appendix 1, Section C.

(6) Views of the Board

The Board has considered the proposed route of the transmission line and having regard for the fact that no objections were received for the portion of the line from Wabamun to the eastern edge of Sections 1 and 12 of Township 53, Range 2, West of the 5th Meridian, concurs with the applicant's choice of that part of the route. With respect to the area east of Range 2, which covers the most easterly five miles of the line, the Board believes further consideration should be given to the route, particularly with respect to Sections 4, 5, 8 and 9 of Township 53, Range 1, West of the 5th Meridian. The detail of this portion of the route is marked Section C in Appendix 1.

The problems to be resolved relate to the properties of Mr. J. D. Fuhr, Mr. Raymond Darimont and Mr. J. Tyminsky. These are located in the adjoining Sections of 5 and 4, Township 53, Range 1, West of the 5th Meridian.

Mr. Raymond Fuhr who is an owner of a portion of the Beach Corner property in the South-west quarter of Section 8, Township 53, Range 1, West of the 5th Meridian objected to the location on grounds of property devaluation and interference with mobile radio reception.

The Board notes that the proposed location of the line was purposely selected to avoid the Beach Corner development including Mr. Fuhr's property. It would appear to be located at least three to four hundred feet distant from his home. The Board also notes that the basis of Mr. Fuhr's objection is the proposed location of the line and towers (in this case single wooden poles are used) within a few feet of the east boundary of his property. However, the Board is not able to assess the question of property devaluation because of the location of the transmission line and in any event the question of compensation is a matter outside the jurisdiction of this Board.

No clear evidence was given at the hearing to determine how serious the question of radio interference with Mr. Fuhr's two-way radio system might be or what steps might be taken to correct any problem of this kind. The Board believes that Calgary Power would be prepared to take any reasonable action to correct interference which the transmission line may cause on the radio system between Mr. Fuhr's residence and his business operation in Spruce Grove.

Under these circumstances the Board believes that the route of the transmission line in the North-west quarter of Section 5 as selected by the applicant, and returning to the blind line as shown on Appendix 1, Section C, is satisfactory and will involve fewer land owners and be better located than other alternative routes that have been considered.

Mr. Raymond Darimont submitted that as long as the transmission line ran adjacent to the blind line along the north side of his property in the North-east quarter of Section 5, and similarly in the North-west quarter of Section 4, both in Township 53, Range 1, West of the 5th Meridian he would have no objection. This location presents a problem for Mr. James Miller who is the owner of 1.6 acres of land (a parcel approximately 260 feet square) in the North-west corner of Section 4, Township 53, Range 1, West of the 5th Meridian.

The Board believes that a compromise solution which would allow for the concerns of both Mr. Miller and Mr. Darimont would be to amend the route of the transmission line so that it returned north to the blind line in the North-west quarter of Section 4 immediately adjacent to the east boundary of Mr. Miller's parcel of land. Mr. Miller's property therefore would be avoided and Mr. Darimont's requirement would be met. This amended route is shown on Appendix 1, Section C.

The Board also believes that the route should be extended eastward along the blind line and through the north 40 feet of Mr. Darimont's land to the north 40 feet of Mr. John Tyminsky's property on the North-east quarter of Section 4, Township 53, Range 1, West of the 5th Meridian. To avoid the existing Hubbles Lake subdivision, the 40-foot width of right of way will be located in the North-west and North-east quarter of Section 4. The Board believes that this is a better solution than crossing the 40-foot strip of Mr. Tyminsky's property at a distance of approximately 280 feet south of his north boundary, and will have less impact on future developments or servicing of the land as outlined in Mr. Tyminsky's submission.

Mr. Tyminsky stated that the property immediately north of his quarter section should participate in supplying some of the right of way. This is subdivided property involving 16 parcels of land on which the right of way would also involve tree cutting at the rear of each of these parcels. The Board believes that the public interest is better served by not encroaching on the existing subdivision and, if and when Mr. Tyminsky should subdivide his land, at least the prospective owners will be aware in advance of the location of the transmission line.

DECISION

The Board has already issued permits for Section A and Section B of the transmission line route as shown on Appendix 1. This action was taken on the basis of evidence submitted by the applicant, the absence of any intervention pertaining to these sections of the route, and desirability of completing the line to supply energy requirements of Trans Mountain Pipe Line as soon as possible. The final decision of the report therefore deals with the route of the transmission line in Section C, (Appendix 1), which involves the remaining five miles at the eastern end of the route.

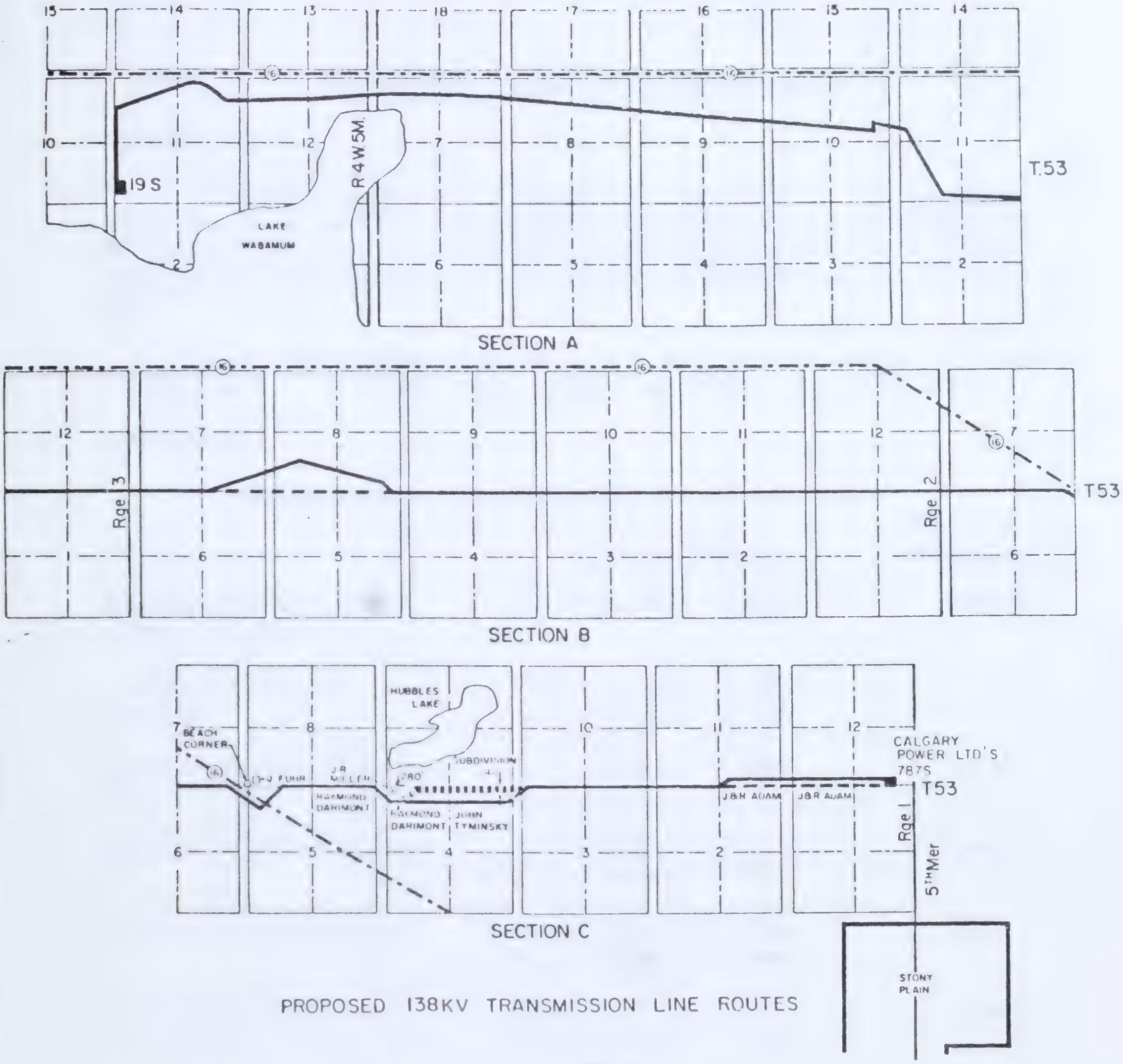
The Board after considering the evidence given at the hearing and examining the proposed route and alternatives has decided that the route should be amended in Section 4, Township 53, Range 1, West of the 4th Meridian as outlined in Section C of Exhibit 1 attached.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard
Vice Chairman

/Attachment

DATED at Calgary, Alberta
February 13, 1973



PROPOSED 138KV TRANSMISSION LINE ROUTES

1. – – – SECTIONS WHERE CHANGES WERE MADE BY CALGARY POWER LTD. BEFORE HEARING
2 ——— FINAL ROUTE PROPOSED BY CALGARY POWER LTD. BEFORE HEARING
3 ▮▮▮▮▮▮▮▮ CHANGES BY THE BOARD
4 ·—·— HIGHWAY NO. ⑯

DECISION 73-3 APPLICATION 6645

APPENDIX I

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-4
Proceeding No. 6700

ANNUAL RESERVES AND PRODUCTIVE CAPACITY

HEARING

A hearing was held by examiners appointed by the Board for the purpose of hearing representations respecting the recoverable reserves of crude oil, the recovery factor modifiers and the productive capacity of pools listed in the Notice of Hearing issued on December 6, 1972.

The hearing was conducted by N. A. Strom, P. Eng.; V. E. Bohme, P. Eng.; and L. A. Falkenberg, P. Eng. on January 15 and 16, 1973.

APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Amerada Minerals Corporation of Canada Ltd.	S. O. Asekun, P. Eng.	Amerada
Ashland Oil Canada Limited	R. A. Beamish, P. Eng. J. A. Howard, P. Eng.	Ashland
Atlantic Richfield Canada Ltd.	D. L. Bowman, P. Eng. E. Chwyl	Arcan
Chevron Standard Limited	J. D. Scott, P. Eng. A. R. Bamsey, E.I.T.	Chevron
Gulf Oil Canada Limited	T. E. Randall, P. Eng. M. J. Melnyk, P. Eng.	Gulf
Imperial Oil Limited	J. W. Pollock, P. Eng. B. T. Reilly, P. Eng. R. Steele	Imperial
Mobil Oil Canada, Ltd.	G. C. M. Derbowka, P. Eng. G. E. Evens, P. Eng. D. C. Campbell, E.I.T. R. M. McManus	Mobil
Supertest Investments and Petroleum Limited	R. G. Kessler, P. Eng.	Supertest
Sun Oil Company Limited	E. J. Pacholko, P. Eng. J. J. Driedger, P. Eng. C. W. Weeks, P. Eng.	Sun
Texaco Exploration Canada Ltd.	F. Thompson P. Houle, E.I.T.	Texaco

	Represented by	Abbreviation Used in Report
Energy Resources Conservation Board	R. G. Evans, P. Eng. G. R. Heming, P. Eng. R. A. Purvis, P. Eng.	Board Staff

Views of operators, views of the examiners, and recommendations of the examiners concerning the submissions are set out in sections as indicated below.

RESERVES SUBMISSIONS

Section	Pool
1.00	Bellshill Lake Blairmore Pool
2.00	Carson Creek North Beaverhill Lake A Pool
	Carson Creek North Beaverhill Lake B Pool
3.00	Nipisi Gilwood C Pool
4.00	St. Albert Big Lake D-3A Pool
	Glen Park D-3A Pool
	Westerose D-3 Pool
	Bonnie Glen D-3A Pool

PRODUCTIVE CAPACITY SUBMISSIONS

Section	Pool
5.00	Nipisi Gilwood A Pool Pembina Cardium Pool Pembina Keystone Belly River B Pool Pembina Keystone Belly River C Pool Pembina Keystone Belly River M Pool Redwater D-3 Pool Willesden Green Cardium A Pool Bantry Mannville A Pool

6.00 RECOMMENDATIONS OF EXAMINERS

1.00 Bellshill Lake Blairmore Pool

1.10 Foreward

Several approaches to the difficult problem of estimating reserves for the Bellshill Lake Blairmore Pool (hereinafter designated the Bellshill Lake Pool) have been used in the past. One approach was to sum the extrapolated recovery expected from each tract or from each well. However, this approach must be used with caution since it assumes that the performance of each well has been, and will continue to be, independent of the performance of the other wells in the pool. A second approach was to establish terminal cone heights (sandwich losses) for each tract and calculate the tract volume swept by water. This approach must also be used with caution since it assumes the effective drainage radius of the well(s) to equal the tract radius. A third approach was to establish a sandwich loss based on the highest wells in the pools and calculate the reservoir volume to be swept by a rising oil-water interface. Unfortunately this approach must also be used with caution since it assumes there will be good lateral migration of oil, and that the pool operation would be viable when only a few wells remain operative.

The recognized reserves for the Bellshill Lake Pool was increased from 50 million to 80 million stock tank barrels on May 1, 1971, on the basis of a primary depletion study supported by radial and 2-D modelling. These studies resulted in an empirical correlation for terminal cone height. At that time the Board concluded that the cone height correlation (fan plot) and methods used to estimate the reserves were somewhat unproven. The Board stipulated that the cone height correlation be reviewed and updated after one year, and that the reserves for the pool be reviewed at the 1973 annual reserves hearing.

Arcan submitted an updated version of the fan plot to the Board on April 6, 1972. The January 1972 production data for the 31 wells used to develop the fan plot showed considerable scatter on the updated plot and generally did not confirm the validity of the original correlation.

1.20 Oil In Place

(1) Views of Arcan

Arcan submitted that the original oil in place is 254,828 thousands of stock barrels (MSTB) compared to the Board recognized value of 238,000 MSTB. Arcan believes its estimate is conservative because:

(a) it does not include oil in the transition zone,

(b) it does not consider the data for 30 infill wells which have an average pay thickness of 1.6 feet greater than previous mapping indicated, and

(c) the northwest extension to the pool is likely larger than it is presently mapped due to lack of well control.

(2) Views of Examiners

The examiners agree with Arcan that in view of the northwest extension and infill drilling results, the oil in place currently recognized by the Board is low. Having regard for Arcan's net oil pay map and an interpretation by the Board staff, the examiners recommend an oil zone rock volume of 165,000 acre-feet. This rock volume and the previously established rock and fluid properties results in an original oil place of some 258,000 MSTB.

1.30 Recovery Factor Calculations.

(1) Views of Arcan

Arcan's average recovery factor of 0.3778 was calculated by separating the 104-forty acre tracts into four categories. A different prediction method was used to calculate the recovery for each category. Different prediction methods were used because Arcan does not believe that the concept of an "average Bellshill Lake well" is valid. Arcan stressed that expansion of the field operating facilities to provide for 80 thousand barrels of liquid per day treating capacity and installing increased lifting capacity which has recently permitted production to exceed 8000 barrels of oil per day is evidence of its confidence in its reserves forecasting methods.

Arcan had classified wells according to production performance in previous submissions. The current method differs substantially in that the recoveries are related to factors distinct from past performance including inhibition of water coning due to shale barriers present around the well bore and inhibition of water coning by a dual completion production technique. The results of Arcan's calculations are summarized in the following table.

Prediction Method	Tracts	Wells	OOIP MSTB	Recovery Factor	Reserve MSTB
Method 1					
Tracts with distinct shale break to inhibit coning	41	56	105,219	0.476	50,063
Method 2					
Tracts with clean sand dual completion candidate	19	30	56,780	0.484	27,482
Method 3					
Tracts where water cut extrapolations were used	14	17	30,894	0.241	7,437
Method 4					
Tracts for which updated fan plot was used	27	34	57,308	0.196	11,223
Tracts currently unproductive	3	3	4,627	-	79
TOTALS	104	140	254,828	0.378	96,294

The four categories and prediction methods used are discussed separately.

Method 1 Tracts Where A Distinct Shale Break Inhibits Water Coning.

The recovery of 0.476 was based on the results of a recent radial coning simulation study for well 9-21. The model was adjusted to match the production history, and then predictions were made for the following cases: continued depletion at 140 barrels of fluid per day (BFPD) from the existing perforations, depletion assuming the lowest perforations are plugged back, depletion assuming that a dual completion technique is implemented, and depletion at 1600 BFPD assuming that the well was reperforated and a high volume pump installed. Arcan concluded from the simulation study that the optimum depletion would be obtained by squeezing off the lowest perforations and producing 500 BFPD from a 10 feet interval which includes the two uppermost perforated intervals.

The calculated recovery factor is based on modelling results which indicate that a one foot shale break of 28 foot radius or greater will effectively control water coning. The calculated recovery factor of 0.476 was applied to all tracts where it was believed a shale break would be effective in controlling water coning.

Method 2. Tracts With Clean Sand.

The recovery factor for this category was based on the terminal cone height from a previous coning model study (D & S Petroleum Consultants Ltd., April 1970) of a dual completion technique for well 13-16. It was assumed that the proposed upper completion in well 13-16 was produced at 80 barrels per day and the lower completion was produced at 500 barrels per day. At the hearing Arcan indicated that it was the balance between rates for the two completions that was important, and that the recovery would not change significantly if both rates were proportionately lower. Arcan believed that the dual completion technique which requires installation of two strings of tubing with simultaneous pumping through each string, could be successfully implemented on wells with production casing sizes of 5½ inches or larger. The calculated recovery factor of 0.484 was applied to all clean sand wells.

Method 3 Historical Performance Extrapolations.

Ultimate reserves for 14 tracts (17 wells) were estimated by extrapolating water cut versus cumulative oil production plots to a limiting water cut. While the average recovery factor for this category was 0.2407, individual well recovery factors varied from 0.03 to 0.43.

Method 4 Tracts Where Updated Fan Plot Was Used.

A modified fan plot was used to estimate the terminal cone height for 27 tracts (34 wells). The average recovery factor for this category was 0.1961 with individual tract values varying from 0.06 to 0.41. The original fan plot was modified by dividing the total fluid rate by the logarithm of the average permeability from core analysis.

(2) Views of the Examiners

The examiners agree with Arcan that the concept of an "average well" for the Bellshill Lake Pool is not suitable. They believe that ultimate recovery will be determined to a great extent by water coning tendencies of individual wells and to a minor extent by the tendency for oil to migrate (be displaced) to the crestal levels of the pool where the pay thickness is largest. The specific views of the examiners with respect to the four methods used by Arcan to estimate the ultimate reserve are set out below.

Method 1. In view of the assumptions involved in calculating the recovery factor for well 9-21, the examiners question the reliability of the estimate and the suitability of applying this recovery factor to such a large group of wells. The examiners also question whether the shale breaks in this category of wells are effective in reducing the tendency for water coning. The cumulative water-oil ratio (WOR) for all wells in this category is 1.51, compared to 1.52 for the pool as a whole, and 1.54 for all the wells in the other three categories. The examiners conclude that Arcan's categorization may not be valid and that its conclusion about the recovery to be obtained from these wells is unduly optimistic. The examiners believe that a recovery factor in the order of 0.25 may be more representative for this group of wells.

Method 2. The recovery factor for the group of clean sand wells is based on modelling calculations and it is assumed that a successful dual completion can and will be made on every well in this category. The examiners note that field testing of the dual completion technique has been performed on only one well to date and that the results are inconclusive. The examiners therefore conclude that it is premature to assume the method is a proven recovery technique. The examiners accept, however, that this group of wells should have the highest recovery and they believe, on the basis of current data, that a recovery factor of some 0.30 is appropriate for the group.

Method 3. The examiners believe that considerable error can be introduced when trying to extrapolate the generally low slope of the plot, water cut versus cumulative oil production. For example, some extrapolations indicate that there will be an increase in the quantity of oil which will be recovered during each successive increase in producing WOR, an illogical occurrence for a well bore drainage mechanism. The issue appears to be whether or not the water cut will "stabilize". The examiners note that when WOR is used in plots of production statistics, a trend of increasing WOR is established for each fixed set of operating conditions such as completion interval, total fluid rate and hours on pump. They also note a linear trend is usually established when the logarithm of (WOR + 1) is plotted versus cumulative oil. When this trend is extrapolated to a limiting WOR, it generally gives a lower reserve than that by extrapolation of water cut. On this basis, the examiners believe that a recovery factor of some 0.15 would be representative for this group of wells.

Method 4. The examiners believe that although the modified fan plot may be an improvement over the original correlation, there are still uncertainties involved in its use. Both correlations assume that water cuts for individual wells become stabilized and change only with an overall rise in the oil-water contact. While the examiners note that water-oil ratios do not appear to become stabilized, Arcan's 0.196 recovery factor appears to be commensurate with well performance. Although the examiners have some reservations respecting the fan plot, they believe that the 0.196 recovery factor is appropriate for this group of wells.

The examiners have observed that the much increased production rates of the past year have been obtained from wells which, in the past, had experienced little or no water coning.

The examiners therefore conclude that the additional experience has not helped to reduce the considerable reservations expressed by the Board at the time when the reserves were increased to 80,000 MSTB. They have determined that, if coning were to occur more-or-less unchecked, the original recoverable reserves could be as low as 40,000 MSTB. After taking into account all available evidence including provision for additional infill wells, the examiners have concluded that original recoverable reserves should be set at 60,000 MSTB.

2.00 Carson Creek North Beaverhill Lake A Pool and Carson Creek North Beaverhill Lake B Pool

2.10 Description of the Pools

(1) Views of Mobil

The Carson Creek North Beaverhill Lake A Pool (hereinafter called the A Pool) and Carson Creek North Beaverhill Lake B Pool (hereinafter called the B Pool) have been interpreted by Mobil from geological evidence of drilled wells as being composed of two biostromal reef reservoirs in the Swan Hills member of Upper Devonian Beaverhill Lake Formation. The reservoirs were found to be separated by an impermeable green shale barrier of approximately 5 to 10 feet encountered at all wells drilled in the field at the present time. Mobil stated that the two reservoirs are separated from the nearby Carson Creek gas field to the south and from the Judy Creek South oil field to the north by erosional channels.

In the course of the history matching phase of Mobil's mathematical simulation performed on each pool, it was necessary to introduce communication between the pools. Mobil concluded that this communication exists along the eroded edges of the A Pool.

Mobil stated that the A Pool is a saturated reservoir with a bubble point pressure equal to the initial pressure of 3698 pounds per square inch gauge (psig). The B Pool, however, in spite of some evidence of an associated gas accumulation, was assumed to be undersaturated. This assumption is supported by three reservoir fluid samples exhibiting bubble points in the range of 3205 psig to 3312 psig as compared to an initial reservoir pressure of 3730 psig. Mobil contended that the presence of the gas cap is not clearly evident and that it may be possible that the gas cap has not yet reached equilibrium with the oil column.

(2) Views of the Examiners

The examiners are in agreement with the basic geological description of the pools presented by Mobil. They note that the green shale barrier was encountered in all wells drilled in the field and also that the reefs are situated in an area in which there could be communication with other nearby pools through a common aquifer.

The examiners agree with Mobil's interpretation of the reservoir fluid properties for both the A and B Pools which were previously accepted by the Board and showed a difference of 340 psi in bubble point pressure. The examiners conclude that drill stem test data does not appear to confirm the presence of a gas cap in the B Pool

In summary, the examiners find that geological evidence and reservoir fluid properties point to separate non-communicating pools. Moveover, the examiners believe that the history match in the B Pool could be affected by aquifer communication with other nearby pools, notably the Carson Creek gas pool to the south. The history matching studies, therefore, may not be a valid basis for assuming even limited communication between the A and B Pools. The examiners conclude that the A Pool and the B Pool should remain as now designated and that evaluations of reservoir performance should be based on considerations of fluids injected and withdrawn, production performance, pressures, et cetera on the premise of no fluid movement between those pools.

2.20 A Pool Oil In Place

(1) Views of Mobil

Mobil proposed a rock volume of 268,099 acre-feet from which an oil in place of 80,900 MSTB is calculated. This estimate of oil in place was confirmed by the history matching phase of Mobil's mathematical simulation studies.

(2) Views of the Examiners

The examiners recommend the adoption of a rock volume of 285,000 acre-feet and a porosity of 0.080 which resulted in an oil in place of 84,600 MSTB for the A Pool.

2.21 B Pool Oil In Place

(1) Views of Mobil

Mobil proposed that the reservoir rock volume be increased from 733,091 to 815,602 acre-feet and the connate water saturation be decreased from 0.21 to 0.137. These changes were made to increase the oil in place to correspond to that volume required to match the pressure history of the pool.

The rock volume increase was generated by lowering the original oil-water interface by five feet. Mobil stated that, although it may have been more correct to adjust the pool's areal limits, changing the oil-water interface depth could be more easily incorporated into the model's grid system.

The connate water saturation of 0.206 previously employed by Mobil for the B Pool was based on mercury injection data. This value is now believed to be incorrect when compared to oil base core data taken from the well in 6-2-62-12 W5M which indicated an immobile water saturation of less than 0.10. The connate water saturation was correspondingly reduced to 0.15 in those parts of the pool underlain by the aquifer and 0.10 in the remaining areas of the pool.

As a result of the history matching phase of its study, Mobil recommended that an oil in place of 305,400 MSTB be set for the B Pool.

(2) Views of the Examiners

The examiners agree with Mobil that oil base core data indicate a lower average connate water saturation than presently set. The examiners believe that a connate water saturation of 0.16 is reasonable for the B Pool.

The examiners propose an increase in reservoir rock volume from 733,091 acre-feet to 785,000 acre-feet, noting that the pool limits are partially undefined particularily on the south and south-eastern flanks of the reservoir.

The examiners recognize that the oil in place recommended by Mobil and supported by its history match is within the possible range of volumetric interpretations. However, it appears to be at the high end of the range and also, the history match may be subject to error if communication exists between the B Pool and the Carson Creek gas pool to the south. Consequently, the examiners recommend that a volumetric estimate of 273,000 MSTB be adopted for the B Pool.

2.30 Recovery Factors

(1) Views of Mobil

Mobil contended that the waterflood schemes in the pools may flush the reservoirs partly through a bottom water displacement mechanism. In support of this, Mobil was able to match water breakthrough times assuming segregated flow. Mobil also made predictions for dispersed flow which indicated breakthrough times much earlier than those experienced. However, it acknowledged that the grid size and shape of the relative permeability curves could render the dispersed option predictions invalid. Upon questioning, Mobil stated that it did not perform a 2-D cross sectional model to confirm its conclusions that the dominant flow pattern was vertical. Mobil also testified that it was "not particularly solid on this point of whether the flood is vertical or horizontal". Mobil cited production tests on the well in LS 6-31-61-11 W5M plus its observations that vertical permeabilities in the reef rim are fairly high, as evidence that vertical displacement could be expected. The 6-31 well had produced at a water cut of 95% through perforations in the lower part of the pay section and upon being plugged back and re-perforated near the top of the section, it produced large amounts of oil at a negligible water cut.

Based on the assumption of a vertical displacement as the dominant recovery mechanism, Mobil calculated recovery efficiencies of 0.514 and 0.567 for the A and B Pools respectively.

(2) Views of the Examiners

The examiners have determined that if the displacements are largely vertical, the recovery efficiencies could be greater by fractions of 0.05 for the A Pool and 0.07 for the B Pool, than if the displacements are largely horizontal.

Regarding the B Pool, the examiners accept that the recompletion of the 6-31 well may be an indication of vertical displacement. The examiners note that Mobil has not performed 2-D vertical predictions to further verify its view that vertical displacement may predominate. They also believe that connection of the B Pool to an aquifer common with the Carson Creek gas pool may be causing some efflux of injected water away from the B Pool. In that event the actual volume of injected water which has invaded the B Pool may be less than that assumed by Mobil, and the attempts to match of breakthrough times may not be meaningful. Respecting the A Pool, it appears that either horizontal or vertical displacement could be assumed with minor effects on matching of breakthrough times. The examiners also note that description of relative permeability curves could have a considerable effect on prediction of breakthrough times using the dispersed option (i.e. horizontal displacement).

Based on the evidence before them, the examiners believe that it is premature to conclude that recovery efficiencies in the A and B Pools will be improved by the advent of vertical displacement. The examiners therefore recommend that the assigned recovery efficiencies remain unchanged at 0.45 for the A Pool and 0.47 for the B Pool.

3.00 Nipisi Gilwood C Pool

3.10 Oil In Place

(1) Views of Sun

Sun submitted that the original oil in place of the Nipisi Gilwood C Pool should be increased from 27,800 MSTB to 34,800 MSTB based on an increase in the rock volume confirmed by additional drilling in the northern and southern portion of the pool. Sun requested that the remaining reservoir factors, including recovery efficiency, remain unchanged.

(2) Views of the Examiners

The examiners accept that some increase in the rock volume of the pool is justified based on new drilling evidence and re-evaluation of existing evidence. However, the examiners believe that the proposed extension of the upper sand into an [illegible] area in the north western portion of the pool is unjustified. Applying a re-evaluation of the existing core analysis data and on core analysis data from three new wells, the examiners recommend that the pool average porosity be decreased from 12.4 per cent to 12.0 per cent. Based on these changes, the examiners recommend that the original oil in place of the Nipisi Gilwood C Pool be increased to 30,100 MSTB.

3.20 Assignment of Oil In Place to Primary and Secondary Recovery Areas

(1) Views of Sun

Sun recommended that the rock volume subject to waterflood be calculated by using a ratio of validated waterflood acreage to pool total validated acreage. The primary acreage was determined by summing the 160 acre DSU's for each of the 5 primary wells.

(2) Views of the Examiners

The examiners believe that a more appropriate method of determining the rock volume subject to waterflood would be to include oil within the project area plus neighboring undrilled fringe areas not being drained by primary wells.

4.00 Golden Trend Pools

4.10 Definition of Issues

The reserves of those pools in the Golden Trend of D-3 reefs subject to primary depletion (i.e. St. Albert-Big Lake D-3A, Glen Park D-3A, Bonnie Glen D-3A and Westerose D-3, hereinafter called Big Lake, Glen Park, Bonnie Glen and Westerose respectively) were considered at the hearing.

The major issues involved are as follows:

1) Description and behavior of the Cooking Lake aquifer.

2) Formulation of policy for setting primary reserves in communicating pools.

3) Residual hydrocarbon saturations.

4) Recovery factors.

4.20 Aquifer Description and Behavior

The examiners believe that a determination of the effectiveness and expected behavior of the aquifer is a necessary prerequisite to decisions involving the policy to be used to assign recoverable reserves in the pools under consideration.

(1) Views of Imperial

Imperial modelled the Cooking Lake aquifer as being infinite to the north and south ends of the trend by imposing constant pressure conditions at these boundaries. The east and west limits of the aquifer were simulated as closed boundaries. Within the trend, Imperial found it necessary to reduce the permeability at the boundaries of all pools, thus simulating low vertical permeabilities. Imperial also observed restricted communication between Bonnie Glen and Wizard Lake and, to some degree between Homeglen Rimbey and the rest of the trend. As a result, Imperial concluded that the Golden Trend can be regarded as essentially two systems with the dividing line occurring between Bonnie Glen and Wizard Lake. It implied that Bonnie Glen and Westerose will be substantially unaffected by injection into and withdrawals from pools to the north of Bonnie Glen. Imperial's pressure predictions are shown on Figures 4.01 to 4.09.

(2) Views of Gulf

In modelling the Cooking Lake aquifer, Gulf utilized a digital analog of an electric analyser system. In this system, (which has closed boundaries), aquifer support was modelled by varying the location and magnitude of the capacitance in the aquifer cells. Gulf testified that the resulting aquifer model had no physical significance, but rather was the aquifer description which matched observed history. In developing this model of the aquifer, Gulf found it necessary, similar to Imperial, to introduce a fairly substantial resistance to flow between Bonnie Glen and Wizard Lake. In observing very low pressures calculated for some pools in the latter part of the study, Gulf stated that the model was subject to considerable error if carried out for an extended prediction period. Gulf's pressure predictions are shown on Figures 4.01 to 4.09.

(3) Views of Texaco

Texaco's prediction technique required the assumption of an infinite, homogeneous, radial aquifer for each pool. Expressions were written for the effect of interferring pools on the pool under consideration and unsteady state theory was applied to derive the optimum aquifer properties. The results of the pressures predicted in this manner are shown on Figures 4.01 to 4.09.

(4) Views of the Examiners

The examiners believe that, although Imperial's model of the aquifer has physical significance, the assumption of constant pressure boundaries to the north and south simulates an aquifer which is even more effective than an infinite aquifer with a finite permeability. The examiners recognize that, although Gulf's model of the aquifer lacks physical significance it may be useful in suggesting the performance of the trend under the assumption of a finite aquifer. In the opinion of the examiners, the most serious limitation of Texaco's model is that an assumption of a radial infinite aquifer is unrealistic for pools in the Golden Trend.

It is noted that Imperial and Gulf have both arrived at one similar conclusion: that a significant restriction to flow exists between Bonnie Glen and Wizard Lake. Further, the same conclusion can be inferred by comparing Texaco's pressure predictions for these two pools. (Figures 4.05 and 4.06). In addition, an analysis of the pressure history of the two pools indicates that while Bonnie Glen has been influenced by large withdrawals from Westerose South and Homeglen Rimbey, Wizard Lake does not appear to have been affected by these withdrawals. Therefore, the examiners conclude that the trend behaves as two systems, and that the southerly one (Bonnie Glen to Homeglen Rimbey) is not affected significantly by pressure maintenance in the northern part of the trend.

As nearly as can be determined from observation of pressure histories, there is substantial communication between all of the pools from Wizard Lake northward and rates of fluid injection and withdrawal in this area will greatly affect all pools in the northern part of the trend.

In conclusion, the examiners believe that Bonnie Glen and Westerose will not experience the effects of injection in the northerly group of pools but will experience an increased pressure maintenance effect due to water influx from the south as withdrawals from Westerrose South and Homeglen Rimbey are reduced beginning in the early 1980's. Big Lake and Glen Park, however, will be greatly affected by injection and withdrawal in those pools north of Bonnie Glen.

4.30 Formulation of Policy for Setting Primary Reserves in Communicating Pools

The Board, in its letter of March 29, 1972 requested that the operators of the major primary depletion pools in the Golden Trend submit estimates of recoverable reserves in their respective pools assuming that all fluid injection into the trend be discontinued on December 31, 1971 (Attachment 4.10). All of the operators expressed concern over the implications of the Board's letter and forwarded some suggestions regarding the policy to be formulated for the calculation of reserves in pools which are affected by operations in neighboring pools.

(1) Views of Imperial

Imperial stated its opinion that the actual recovery mechanism expected should be recognized in setting the primary reserves. Further, in a communicating system such as the Golden Trend, Imperial stated that the operators of enhanced recovery projects may find it "necessary to compensate for the operation of other pools or projects in order to maintain the project approval". Imperial assumed that injection would be increased in Acheson from 10,000 barrels per day in 1972 to 18,800 barrels per day in 1990 and in Wizard Lake from 54,500 barrels per day in 1972 to 63,000 barrels per day in 1990. Imperial also assumed that pressure maintenance schemes in the Trend would be carried out to depletion, and that failing this, some form of pressure maintenance would be considered for Big Lake.

Imperial also stated, that in a case such as Pembina Cardium, even though a primary area may be adjacent to a waterflood area and receive pressure and productivity benefits from that area, the reserves of the primary area should be set ignoring the presence of the waterflood area.

In conclusion, Imperial expressed its opinion that as the method of distribution of allowables within a pool is different from the method for allocation of allowables among pools, it did not recognize the need to develop a common policy.

(2) Views of Gulf

Gulf expressed the view that if the working interest owners in a pressure maintained pool had no objection to a communicating primary depletion pool receiving recoverable reserves based on observed behavior, then the reserves set for the primary pool should incorporate the benefits derived from neighboring injection. Gulf qualified this view somewhat, by referring to a case where the primary depletion pool was quite small compared to the pressure maintained pool. It indicated that the relative size of the communicating pools was an important factor. Gulf assumed that water injection would be increased in Acheson from 3,500 barrels per day in 1972 to 50,000 barrels per day in 1980 through 2001 and in Wizard Lake from 16,000 barrels per day in 1972 to 120,000 barrels per day in 1996 through 1998. In conclusion, Gulf stated that if the operator of the pressure maintained pool objected, an arrangement whereby this operator would inject water on behalf of the other pool has numerous precedents.

(3) Views of Texaco

Texaco stated its opinion that the calculated recoverable reserves should reflect the actual recovery to be obtained. It contrasted the case of separate pools communicating through the aquifer with different parts of the same pool and stated that, in the latter case, there is an incentive to maintain pressure and therefore prevent the migration of oil. In supporting that view, Texaco stated that there is very little incentive to institute pressure maintenance in some of the pools in the Trend.

(4) Views of the Examiners

The examiners believe that there are two basic questions to be answered respecting operation of pools in a common aquifer with extensive communication among them: firstly, whether the operator of a pressure sink or pressure source pool which is having a significant pressure effect on a neighbouring pool undergoing primary depletion has a responsibility towards the primary pool; and, secondly, whether the positive or negative interference effects of the sink or source pool should be considered in calculating the reserves of the primary pool. The examiners believe that the policy adopted must consider both the correlative rights of the owners in the pools and also the effects on conservation of oil. In this section the terms "strictly primary" and "interference" will be used to identify the two different concepts of reserves calculation being discussed, the "strictly primary" referring to that case where the effects of neighbouring sink or source pools are excluded, and the "interference" where the positive or negative interference is incorporated into the reserves calculation of the primary pool.

Although none of the operators represented at the hearing indicated agreement with the Board's suggestion that a "strictly primary" approach for reserves calculation should be used in the subject pools, some correlative rights matters were raised by these operators. With regard to the Gulf proposal that the Board should apply the "interference" approach to reserves calculations except where an operator in a pressure source pool objected to the operations of a nearby primary pool, the examiners are concerned that this would result in inconsistent treatment of similar situations. The proposal also ignores the conservation aspect, which will be discussed later. Gulf suggested that, if objections were raised by the operator of a pressure source pool regarding depletion by a nearby pressure sink pool, precedents exist for having an operator of the source pool inject on behalf of the sink pool. While the examiners do not necessarily agree that any applicable precedents exist, they do consider that the Gulf approach could be one solution to the pool interference problem.

The examiners recognize considerable merit in the Texaco suggestion that an operator who wishes to deplete a pressure sink pool at abnormally high rates has a responsibility to prevent excessive damaging effects on neighboring pools. Because many such depletion schemes evolve gradually, are of varying degrees, and have effects which are extremely difficult to calculate on affected pools, there would be difficult technical and administrative problems to surmount.

However, conservation and correlative rights benefits would be derived from such an approach.

In the four pools under review, it appears that the percentage difference in recoverable reserves between the "strictly primary" and the "interference" cases is relatively small. The recovery in the "interference" case is higher in all four pools, but the difference varies from only one per cent to five per cent. However, in terms of barrels of recoverable oil, the total difference in the four pools would appear to be about 10 to 15 million barrels, which is a significant amount.

In the Gulf and Imperial studies it has been assumed that in some of the pools in which injection schemes are already operational, the operators would continue to increase injection capacity to extremely high levels in order to maintain pressure in those pools until abandonment. The examiners are of the opinion that these injection schemes could not be expected to increase their injection to unreasonable levels, taking into account the production level from the subject pools, and that the economics of operation of each of these schemes must be considered.

The examiners believe that, if a "strictly primary' policy was adopted, the operators of the non-injecting pool would be encouraged to inject, or to participate in the neighboring scheme, to the possible improvement in oil recovery. Such a policy would be consistent with the approach which has already been applied in certain cases, notably in the Zama and Rainbow areas. The "strictly primary" policy would also be consistent with the policy which is now being applied on a within-pool basis.

Adoption of a "strictly primary" policy would, on the other hand, have the disadvantage that the reserves established would have to be revised periodically to account for pool operations which had occurred different than that assumed in calculating the reserves. Adoption of this approach would also result in carrying reserves for some pools, and for the Province as a whole, which may be lower than the reserves which would ultimately be produced.

In conclusion the examiners believe that pressure interference or energy transfer among pools has similar implications as interlease drainage, whether adverse or beneficial and that the operator of a pressure sink pool has a responsibility to those neighbouring pools which are affected. Note, however, that the examiners would only expect that the Board would become involved in controlling major interference situations, and that minor pressure effects would be tolerated by all parties concerned. It seems likely to the examiners that application of an appropriate maximum rate limitation (MRL), applied to both gas and oil pools, would be a suitable means of dampening serious adverse interference effects. Also, the Board might arrange for a compensatory scheme of operation involving two or more pools as a means of alleviating adverse effects.

The examiners believe that where the source pool is providing pressure support to the energy system, it is reasonable to expect that this injection would continue to replace withdrawals from the pool. The examiners do not believe that the operator of a pressure maintained pool has the responsibility to replace excessive withdrawals from a pressure sink pool.

The examiners conclude that it would be appropriate for the Board to calculate reserves for a sink pool giving recognition to the pressure support which would be expected from continuation of the existing injection operation in an adjoining source pool. The reserves calculation should not, however, assume nor take into account increased injection capacity in the source pools above the injection capacities actually installed.

Similarly, where a sink pool is, in spite of injection, MRL or other controls, having a deleterious effect on a source pool, the reserves calculated for the source pool must take into account the negative pressure interference.

4.40 Residual Hydrocarbon Saturations

Residual oil saturations after water displacement (SORW) and gas displacement (SORG) represent the most important components in estimating the recovery efficiencies for the D-3 pools under consideration. Data concerning residual hydrocarbon saturations are normally obtained from two broad sources: laboratory tests on rock samples, and pool performance calculations based on interface measurements. Gas saturations in the oil zone (critical (1), trapped (2), mobile (3)), may have a significant role in determining residual oil saturations from performance data.

The data presented by the applicants and the values adopted by the examiners for each pool, are discussed in the following section and are tabulated on Table 4.11.

(1) Views of Imperial

Imperial determined SORW to be 0.257 pore volume (PV) from performance calculations in Big Lake. In answer to questions Imperial offered the opinion that the displacement efficiency would be similar by gas and that a trapped gas benefit in the order of 0.03 PV might occur if the pressure were to drop below the bubble point.

(2) Views of Gulf

Gulf used SORW of 0.233 PV for Glen Park and 0.232 for Westerose. These values are based on:

(a) performance calculations on Glen Park,

(b) imbibition tests on 72 Westerose core samples,

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(1) Critical gas saturation - gas which remains immobile in an oil zone; saturation at which gas flow in an oil zone begins to occur (gas saturation increasing).

(2) Trapped gas saturation - gas which remains immobile in an oil zone after displacement by water and in which the gas is presumed to reduce SORW.

(3) Mobile gas saturation - gas moving upward through an oil zone under active gravity drainage; has the same effect as critical gas saturation has on performance calculations.

(c) waterflood tests on three large surface outcrop rock samples from the Spray Lakes area.

Gulf used SORG of 0.186 PV (gas displacement efficiency of 0.80 HCPV) to determine recoverable reserves for Westerose. It stated that, based on laboratory gas flood test data on four Westerose cores and on the Spray Lakes samples, SORG may range from about 0.23 PV to about 0.14 PV. Gulf adopted the general premise that the resiudal oil under downward gas displacement would be roughly 0.05 PV less than that under upward water displacement. When questioned about water and gas displacement tests on the four Westerose core samples which indicated very small difference in residual oil, Gulf stated that it did not completely accept the waterflood results for that set of cores.

Gulf's calculations on Westerose showed that a critical gas saturation of 0.056 PV provided a reasonable match with performance assuming SORG of 0.140 PV and SORW of 0.232 PV. For a similar calculation the critical gas saturation had to be increased to 0.093 PV to provide an interface advance match, if it was assumed that SORG and SORW were the same value of 0.232 PV.

(3) Views of Texaco

Texaco used SORW that varied from 0.354 PV at zero gas saturation to 0.329 PV at 0.10 PV gas saturation, equivalent to a maximum trapped gas benefit of 0.025 PV. A corresponding SORG of 0.245 PV was used. These values are based on the results of water and gas displacement tests on four core samples from Wizard Lake and Bonnie Glen. It was brought to Texaco's attention at the hearing that these tests showed that the oil saturations were reduced to nearly the same level after the same (2 PV) of throughput of either water or gas. Texaco offered no explanation but contended that the above residual oil saturation values are substantiated by performance calculations on Bonnie Glen. To obtain a satisfactory match with the observed interface advance, Texaco also employed a gas saturation of 0.10 PV. In answer to questions, Texaco indicated that part of the gas saturation would be gas "in transit" migrating upward while part of it would be a true critical (immobile) gas saturation.

(4) Views of the Examiners

It is useful to consider a large number of core displacement tests before adopting a general thesis concerning residual oil saturations typical for a given rock type. The examiners note that a tendency to limit displacement tests on D-3 cores to those containing pinpoint, intergranular pores may render the overall results atypical since there would be inadequate representation of rocks containing large vugs.

The examiners believe that the Westerose imbibition tests conducted rather recently provide the most representative set of tests of vugular D-3 core material. Also the tests conducted on large core specimens of vugular rocks obtained near Spray Lakes, while not necessarily representative for D-3 pools, tend to demonstrate that rocks containing a lesser number of large vugs may have lower residual oil saturations for given displacement mechanisms than rocks of similar porosity made up of numerous intergranular interstices. As a general conclusion, the examiners are inclined to accept that the residual oil saturations in the Golden Trend pools will, if anything, tend to be lower than those of other less vuggy, less permeable reefs encountered elsewhere in the Province.

With regard to the relative level of SORW and SORG, the examiners note that comparisons of displacement tests of the same core specimens, given similar initial saturation conditions and like pore volumes of displacing fluid, indicates little difference. The examiners believe that a proper analysis of the Westerose laboratory data is to compare the gas and water displacement tests on the same samples. This shows SORG to be only about 0.02 PV lower than SORW. Similarly, when the Bonnie Glen water and gas displacement tests are compared at the same level of displacing fluid throughput (2 PV), there is little difference in oil saturation.

Matching of performance calculations may lead to the simultaneous adjusting of SORW, SORG, and critical gas saturation given that all other data (pressure, initial hydrocarbons in place, pore volume versus depth, interface measurements, etc.) are fairly reliable. In considering the performance matching calculations, the examiners have regarded the significant variables as being SORW, SORG, critical gas saturation and pore volume versus depth. It is perhaps noteworthy that all performance calculations submitted by operators assumed that volumetric conformance in the swept regions was 100 per cent. The examiners accept this as a reasonable approach since it is probably nearly correct and means that conformance efficiency is implicit in the derived SORW or SORG. On this basis the examiners accept Imperial's performance results for Big Lake indicating SORW equals 0.257, with the observation that the pore volume versus depth correlation may have an error of plus or minus 20 per cent in the volume assumed in the presently swept zone. In other words SORW could be somewhere in the range of 0.20 to 0.30. A similar conclusion seems suitable for Glen Park.

Respecting Bonnie Glen and Westerose, the level of gas saturation in the oil zone complicates the conclusions that may be drawn. Since the pools have been swept largely by advancing gas caps and since the pore volume in the gas swept regions is not likely subject to significant errors, performance match calculations for these pools provide a good opportunity to reconcile SORG and critical gas saturation. On the other hand, positioning of the oil water interface in each pool and making allowances for residual oil losses during limited periods of oil zone encroachment into the aquifer for Westerose, renders interpretation of SORW difficult and also may have a limited effect on interpretation of SORG and critical gas saturation. The examiners have come to the conclusion that SORW of greater than 0.30 as submitted by Texaco for Bonnie Glen is unreasonably high. They have also determined that if, SORG and SORW are about equal at 0.25 PV, then the average gas saturation in the remaining oil zones must be about 0.10 PV. Residual oil saturatuons on the order of 0.15 would be indicated if it were assumed that the oil zone gas saturation was 0.05 PV. The examiners are more inclined to accept that average gas saturations may approach 0.10 PV while SORG and SORW are about 0.25 PV for the group of pools under consideration.

The examiners believe that a trapped gas benefit of 0.02 PV could occur in a waterflood. However, other values have a range of uncertainty such that adjustment for this effect is not justified.

Considering all of the evidence, the examiners believe that SORW of 0.25 PV and SORG of 0.25 PV are appropriate for the high permeability, vuggy D-3 reservoirs studied.

4.50 Recovery Factors

The recoverable reserves in the pools under consideration are a function of three factors discussed previously, which are:

(1) That there is a substantial resistance to flow between Bonnie Glen and Wizard Lake, so that reserves for Bonnie Glen and Westerose will not be affected to any extent by injection of fluids in the northern part of the trend.

(2) For Big Lake and Glen Park, the pressure declines probably will be limited by the influence of injection systems in other nearby pools and/or appropriate maximum rate limits.

(3) The residual oil saturation resulting from gas or water displacement is about 0.25 PV including conformance efficiency effects.

4.51 St. Albert - Big Lake D-3A Pool Recovery Factor

(1) Views of Imperial

Imperial calculated a recovery factor of 0.694 based on negligible pressure decline, (Figure 4.01) a residual oil saturation of 0.257 PV and a fifteen foot sandwich occurring at the crest of the reservoir.

(2) Views of the Examiners

The examiners assume that the Acheson injection system will provide partial pressure support such that the Big Lake pool pressure will decline to about 1250 psig at abandonment (Figure 4.01).

The examiners believe that the Big Lake reservoir properties, including horizontal-vertical permeability ratio, are not significantly different from those of other pools in the Golden Trend. Therefore, for consistency with these pools, the examiners recommend that a five foot terminal oil sandwich near the crest of the pool be assumed. The resulting recovery efficiency is calculated to be 0.72 fraction of the original oil in place.

4.52 Bonnie Glen D-3A Pool Recovery Factor

(1) Views of Texaco

Texaco calculated a recovery factor of 0.673 based on an abandonment pressure of 1350 psig (Figure 4.06), a residual oil saturation of 0.245 PV in the gas invaded zone and varying from 0.354 PV to 0.329 PV in the water invaded zone and a five foot terminal oil sandwich located close to the level of the present oil-water contact.

(2) Views of the Examiners

The examiners assumed an abandonment pressure of 1200 psig recognizing that pressure maintenance in pools north of Bonnie Glen will likely have a negligible effect on that pool, whereas increased pressure support from the southern part of the aquifer is expected to occur when withdrawals from Homeglen Rimbey and Westerose South are reduced.

The examiners also assumed that a five foot sandwich will be left at or near the present oil-water contact. The resulting recovery factor is calculated to be 0.69.

4.53 Glen Park D-3A Pool Recovery Factor

(1) Views of Gulf

Gulf calculated a recovery factor of 0.724 based on negligible pressure decline, a residual oil saturation of 0.233 PV in the water invaded zone and a five foot sandwich at the crest of the pool.

(2) Views of the Examiners

The examiners assumed that the pool pressure will decline to 1800 psig at abandonment (Figure 4.04) and that a residual sandwich of five feet will be left fairly high in the structure. The resulting recovery factor is calculated to be 0.72.

4.54 Westerose D-3A Pool Recovery Factor

(1) Views of Gulf

Gulf calculated a recovery factor of 0.76 based on an abandonment pressure of 480 psig (Figure 4.07), a residual oil saturation of 0.186 PV in the gas invaded zone and 0.232 PV in the water invaded zone and a sandwich of 5 feet close to the original oil-water contact.

(2) Views of the Examiners

The examiners estimate that the pressure will decline to about 1300 psig at abandonment (Figure 4.07). Assuming a sandwich of five feet at the original oil-water interface and that a residual oil saturation of 0.10 PV will remain in the oil invaded aquifer zone, a recovery factor of 0.67 is calculated. Had there not been oil losses to the aquifer the calculated recovery factor would have been 0.68.

5.00 Productive Capacity

The peak value of maximum efficient reservoir capacity (peak MER) is defined as the maximum production rate of a pool which could be developed economically and without detriment to ultimate recovery, assuming an unlimited market and the current crude oil price structure. For this review, an unlimited market was assumed to occur on January 1, 1973. The unlimited market assumption was valid for several capacity-restricted pools. However, there were some pools where proration allowables were less than current pool capacity.

MER capacity submissions were considered for eight pools. Table 5.01 compares the currently recognized peak MER capacity estimates with those submitted by the operators, and those recommended by the examiners.

5.10 Mitsue Gilwood A Pool

Chevron estimated the peak MER capacity of the Mitsue Gilwood A Pool to be 56,000 BOPD attainable after approximately one year. The estimate was based upon a comprehensive MER model study which considered both reservoir behavior and surface facility operation. A rate of 65,000 BOPD was considered, however, this rate required 29 infill wells, a 20,000 BWPD expansion to the injection system, and major surface facility modifications. Chevron stated that an economic analysis indicated that maximum profitability and optimum reservoir performance was achieved with a peak MER capacity of 56,000 BOPD. Figure 5.01 shows Chevron's MER forecast and historical performance to December 31, 1972.

The examiners agree with Chevron that the peak MER capacity is in the order of 56,000 BOPD. The examiners note that Chevron's projected decline corresponds to about 10 per cent per year and they propose to use this value in Board forecasts of provincial productive capacity.

5.20 Pembina Cardium Pool

Mobil submitted productive capacity estimates for seven areas within the pool on behalf of the operators of enhanced recovery projects in the pool. The estimates were based on ten year forecasts of individual project performance. The predicted decline rates for six of the areas varied from about 4 to 14 per cent per year. The seventh area (a low productivity area in the southwest part of the pool) was projected to maintain or possibly increase production rate over the next ten years. Figure 5.02 shows the historical peak oil rates and MER capacity forecast for the enhanced recovery projects in the pool. A peak oil rate of 149,500 BOPD was attained in 1971 and a rate of 64,500 BOPD is predicted for 1983. The predicted composite decline for all projects is about 7 per cent per year. The current peak MER capacity was estimated to be 125,300 BOPD. The primary area currently has a productive capacity of about 10,000 BOPD, hence the current pool capacity is some 135,000 BOPD.

The examiners agree with the forecast of productive capacity prepared by Mobil and Amoco, and they recommend that the 7 per cent decline rate be used to estimate future productive capacity. The examiners note that if the forecast decline is extrapolated, an ultimate recovery of some 1,270,000 MSTB is indicated. Extrapolation of the oil rate versus cumulative plots for the seven areas used in the study gives a comparable result. Thus, there is some evidence to indicate that the currently assigned reserve of some 1,700,000 MSTB for the Pembina Cardium pool may be 300,000 MSTB too high. A more careful review of Pembina reserves including extrapolation of production decline performance should be considered after 3 more years of decline history has been obtained.

5.30 Pembina Keystone Belly River B Pool

The Belly River B Pool contains four enhanced recovery projects and two of the projects have only recently received approval to waterflood. Ashland estimated that a peak MER capacity of 13,660 BOPD would be attained in 1976, and that some 56 infill wells would be required to achieve this peak value. Its estimate was based on predictions by the four major operators in the pool. The individual projects were estimated to have production declines varying from 5 to 15 per cent.

The examiners believe that a 10 per cent decline would be appropriate for the pool as a whole and representative of typical Belly River performance. They recommend that a peak MER capacity of 10,000 BOPD be established for this pool until it can be demonstrated that the infill drilling program will result in the projected productivity increase. Figure 5.03 shows the various MER capacity forecasts and their relationship to the PRL formula.

5.40 Pembina Keystone Belly River C Pool

It is expected that 20 infill wells will be drilled in this pool and that an 80 acre five spot pattern waterflood will be initiated by June 1, 1973. On the basis of a reservoir simulation study of the proposed waterflood, Ashland estimated that a peak MER capacity of 6800 BOPD would be achieved in 1977, and that the oil rate would decline at about 19 per cent per year after reaching the peak MER. This MER capacity forecast is shown on Figure 5.04.

The examiners note that the projected peak MER capacity is some nine times the current primary producing rate. They believe the model predictions to be very optimistic, likely because of way productivity indices were assigned to producing grid blocks. The examiners recommend that until some waterflood performance history is available that a peak MER capacity of 2500 BOPD be assigned followed by a production decline of 10 per cent per year.

5.50 Pembina Keystone Belly River M Pool

Good waterflood response has been achieved in the Pembina Keystone Belly River M Pool. Supertest estimated that a peak MER capacity of 1500 BOPD would be achieved in 1976. It said there was a good possibility for some infill drilling which would correspondingly increase the MER capacity. Figure 5.05 shows the MER capacity forecast.

The examiners believe that the decline on the nine spot pattern will be somewhat lower than on five spot Belly River pools, and they have used seven per cent per year in developing their MER forecast. They also believe that breakthrough to side wells will limit the peak MER capacity to about 1300 BOPD.

5.60 Redwater D-3 Pool

Imperial estimated the peak MER capacity for Redwater D-3 to be 180,000 BOPD and that this rate would be attainable by early 1974. It said that present plans are to install capacity to produce at 165,000 BOPD. Figure 5.06 shows Imperial's MER capacity forecast. It was estimated that the peak MER capacity could be sustained for 1.3 years followed by a decline rate of about 25 per cent per year. Figure 5.07 also shows the rapid increase in water production rate that is forecast as more wet wells are put on production. The corresponding pool performance data is shown on Figure 5.07.

The examiners generally agree with Imperial's forecasts, however they are concerned about the pressure level that will be maintained by natural water influx before supplemental injection is required. It would appear that an average daily oil rate of 165,000 BOPD could require supplemental water injection of over 100,000 BWPD. The examiners note that during the 1.3 years that the pool is at its forecast MER capacity the water production increases from 150,000 BWPD to 450,000 BWPD. They believe that the 15,000 BOPD difference between the peak and average oil rates may not be sufficient to allow for operational problems during this period of the forecast. They agree that with an unlimited market January 1, 1973, the peak MER capacity would be some 180,000 BOPD, however, they believe that the actual market growth will result in an actual average daily rate of less than 165,000 BOPD.

5.70 Willesden Green Cardium A Pool

Based on the data received from all operators in the Willesden Green Cardium A Pool, Amerada estimated the peak MER capacity to be 22,670 BOPD. They estimated that current pool capacity of 16,400 BOPD could be increased by: infill drilling (3800 BOPD), waterflooding primary acreage (1700 BOPD), waterflood response (500 BOPD) and workovers (280 BOPD). Figure 5.08 shows Amerada's MER capacity forecast.

The examiners note that since this pool is incapable of making its allowable, there has in fact been an unrestricted market for the pool. Also since most of the projects have started to decline they do not believe that the peak rate will be increased above 16,000 BOPD. This rate is compatable with a decline rate of some five per cent per year as shown on Figure 5.08. The examiners conclude that 16,000 BOPD is an appropriate peak MER capacity for this pool.

5.80 Bantry Mannville A Pool

Chevron estimated that peak MER capacity of the Bantry Mannville A Pool to be 7075 BOPD. It estimated that the peak rate could be sustained for several years followed by a decline of about 15 per cent per year. Figure 5.09 shows this MER capacity forecast. Chevron said that pipeline scheduling had caused some problems and that this likely accounted for the recent decline in the average oil rate for the pool.

The examiners agree that the peak MER capacity is some 7000 BOPD, however, they expect that the pool will start to decline at about 10 per cent per year in the near future.

RECOMMENDATIONS OF THE EXAMINERS

The examiners recommend that the reserve factors in Table 6.01 and the reserves listed in Table 6.02 and their interpretation of the peak MER's listed in Table 5.01 be adopted.

VIEWS OF THE BOARD

The Board agrees with the recommendation of the examiners.

DECISION

The Board has adopted the reserve factors in Table 6.01 and reserves listed in Table 6.02 and the examiners estimates of the peak MER's listed in Table 5.01. The reserves become effective May 1, 1973.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
February 28, 1973

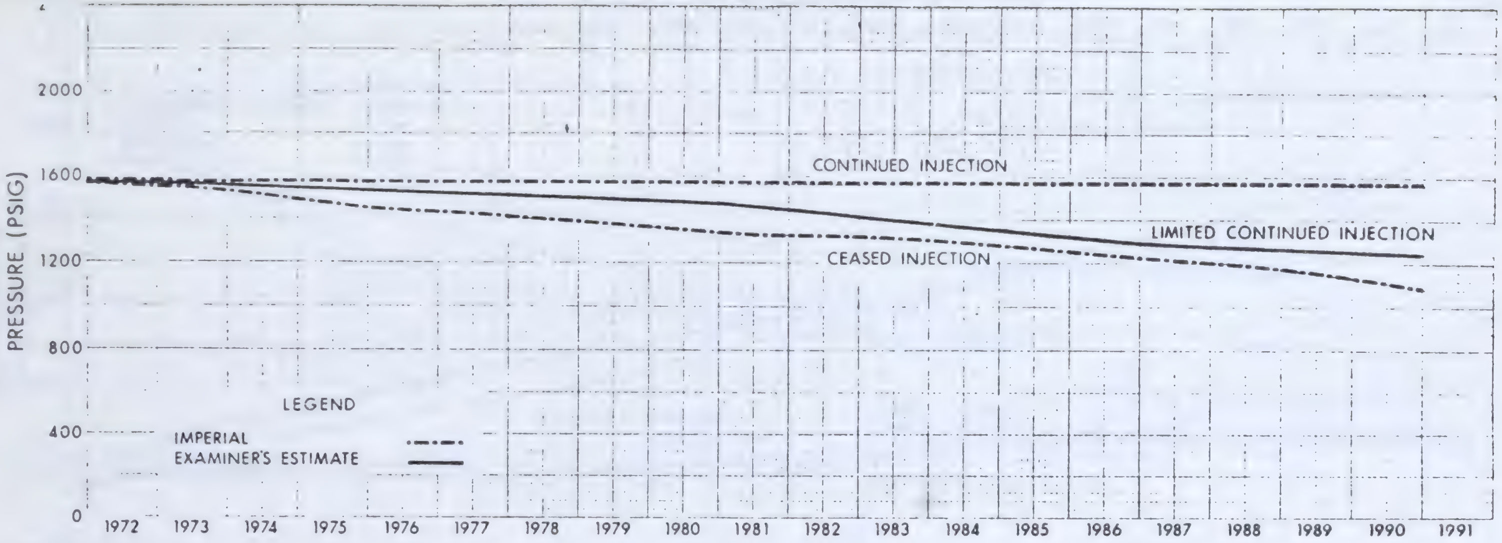


FIGURE 4.01 - ST. ALBERT - BIG LAKE D-3A POOL
PRESSURE PREDICTIONS

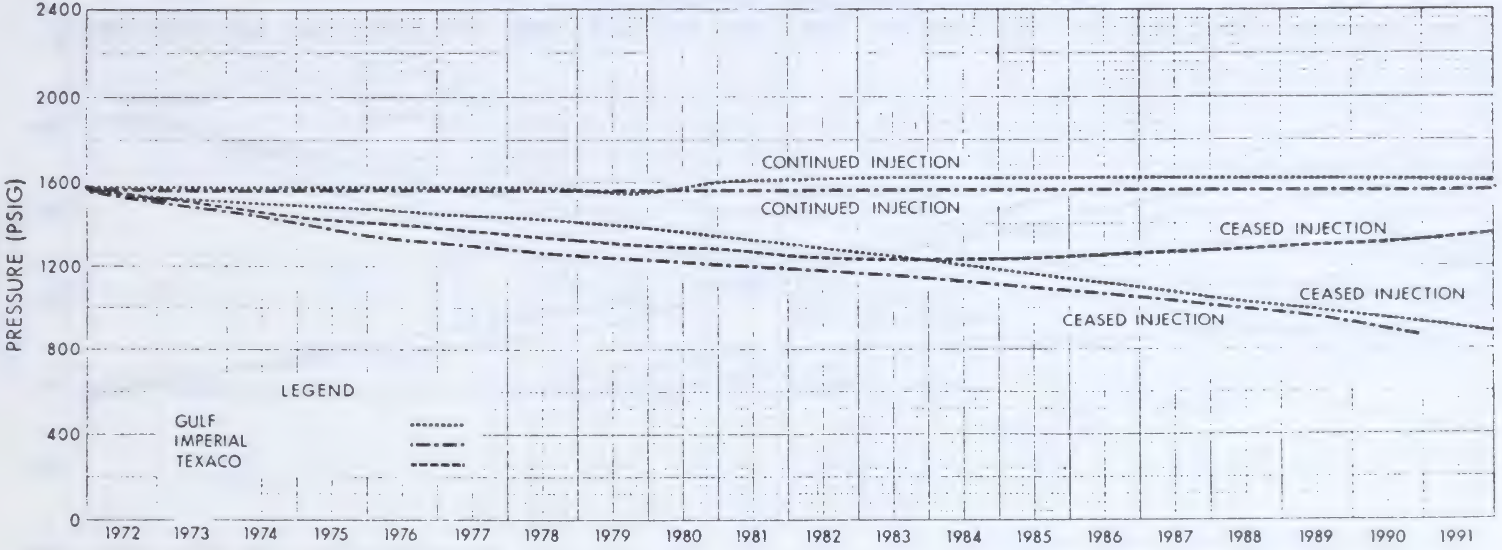


FIGURE 4.02 - ACHESON D-3A POOL
PRESSURE PREDICTIONS

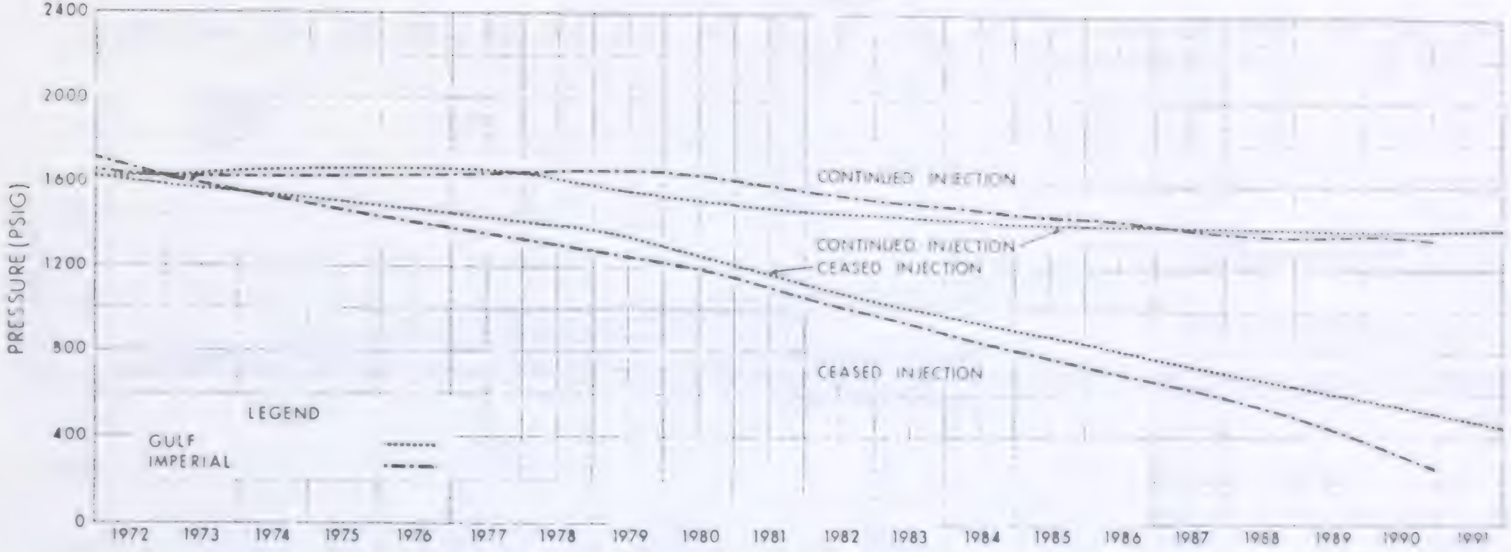


FIGURE 4.03-LEDUC WOODBEND D-3A POOL
PRESSURE PREDICTIONS

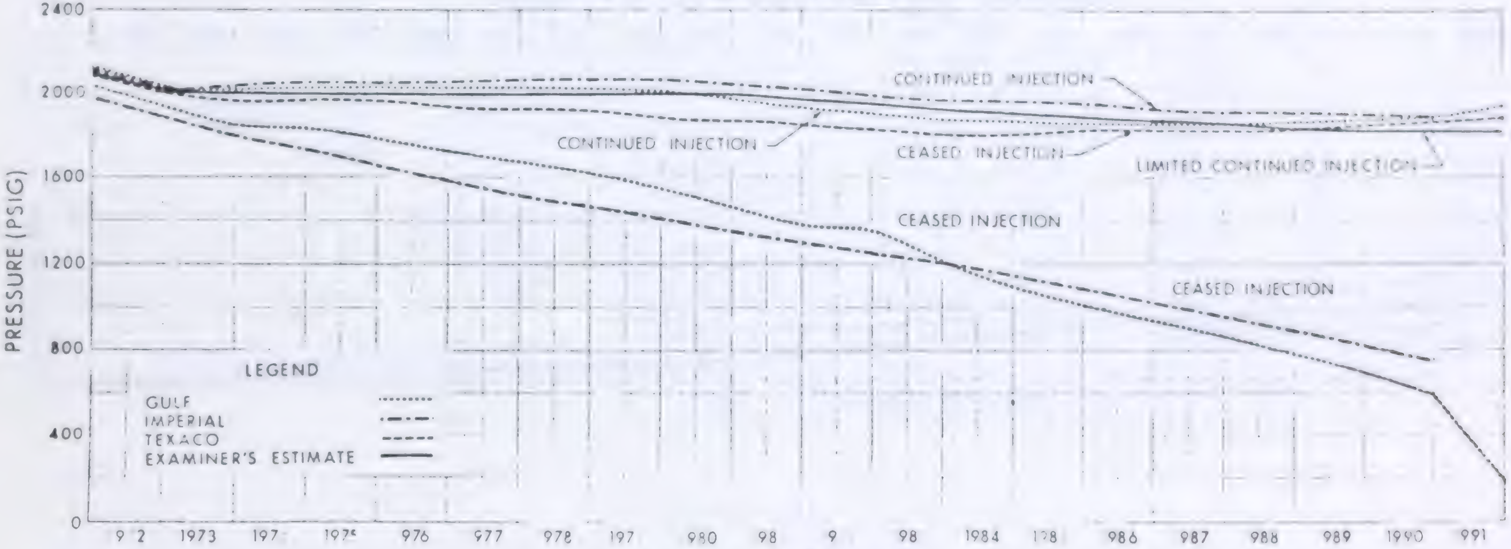


FIGURE 4.04-GLE ARK D-3A POOL
PRESSURE PREDI NS

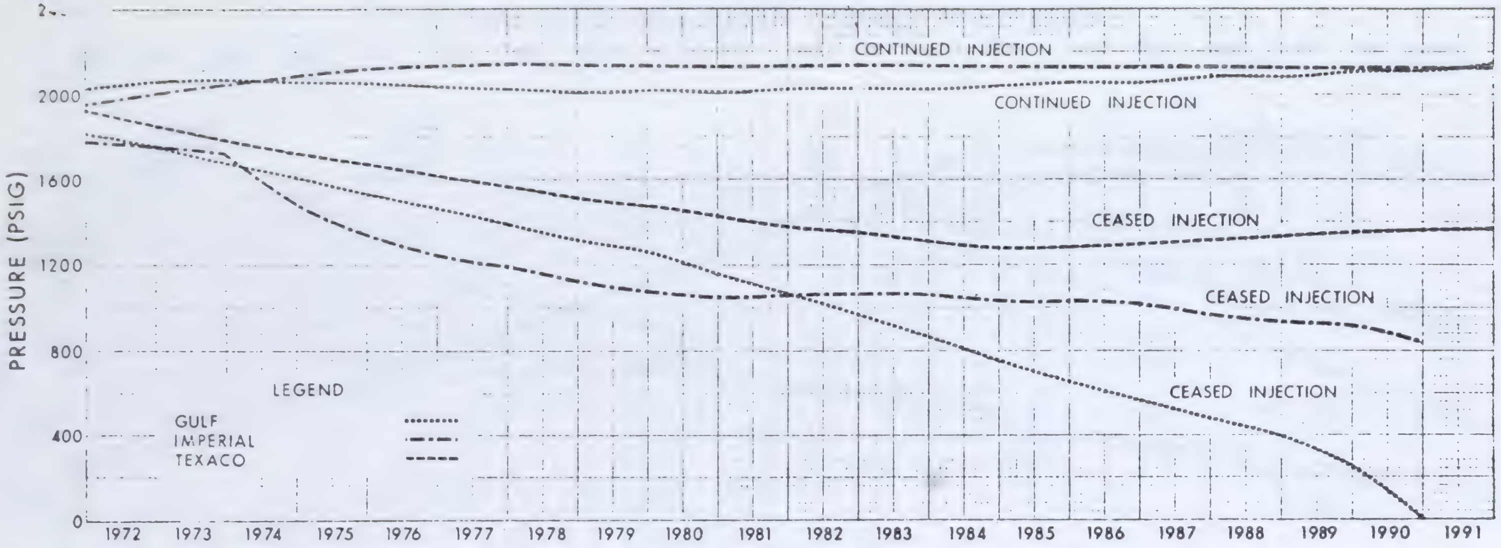


FIGURE 4.05 - WIZARD LAKE D-3A POOL
PRESSURE PREDICTIONS

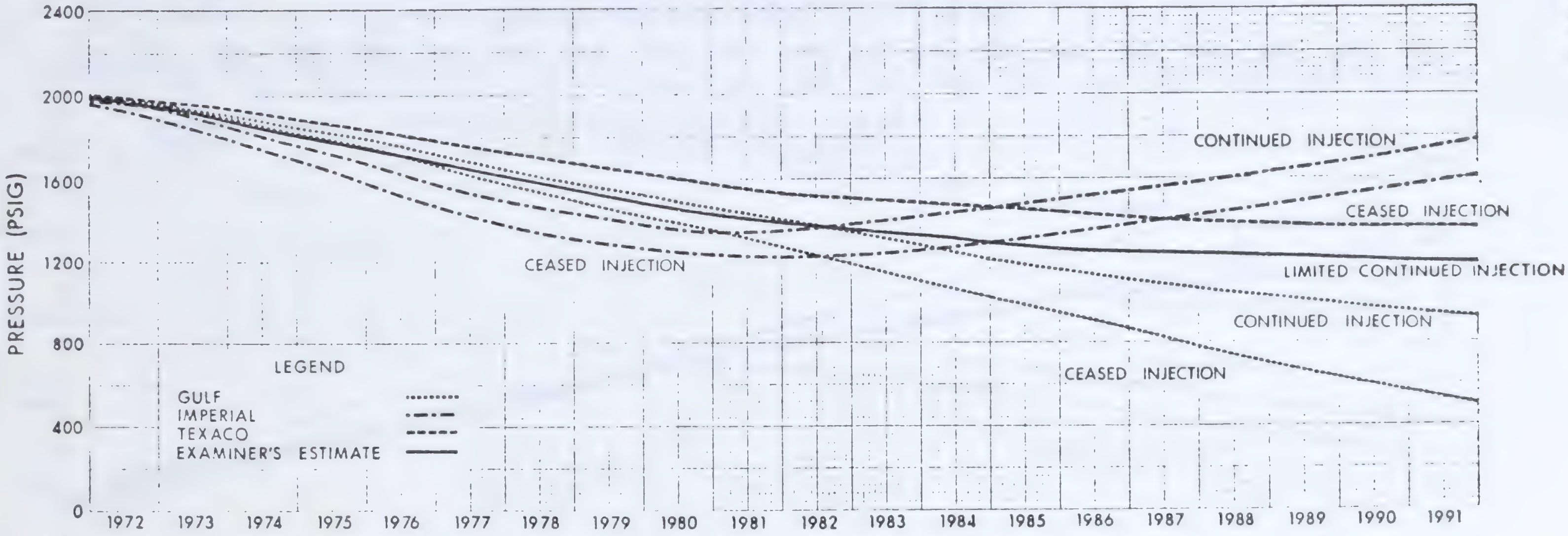


FIGURE 4.06 - BONNIE GLEN D-3A POOL
PRESSURE PREDICTIONS

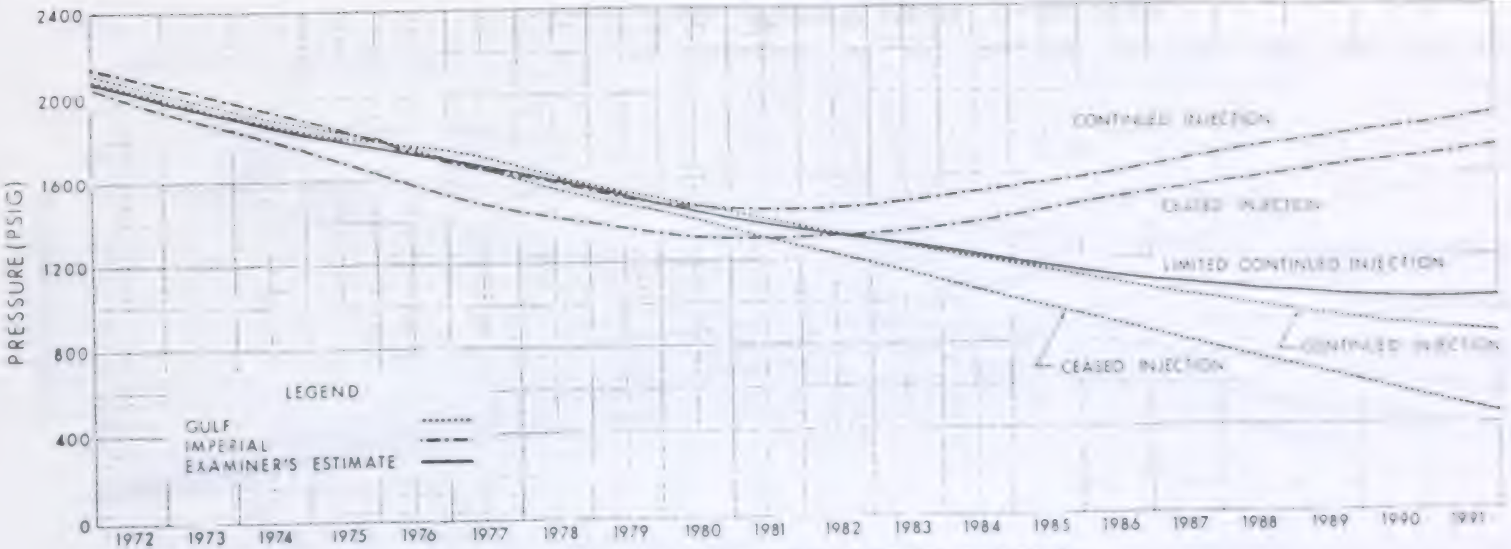


FIGURE 4.07-WESTEROSE D-3 POOL
PRESSURE PREDICTIONS

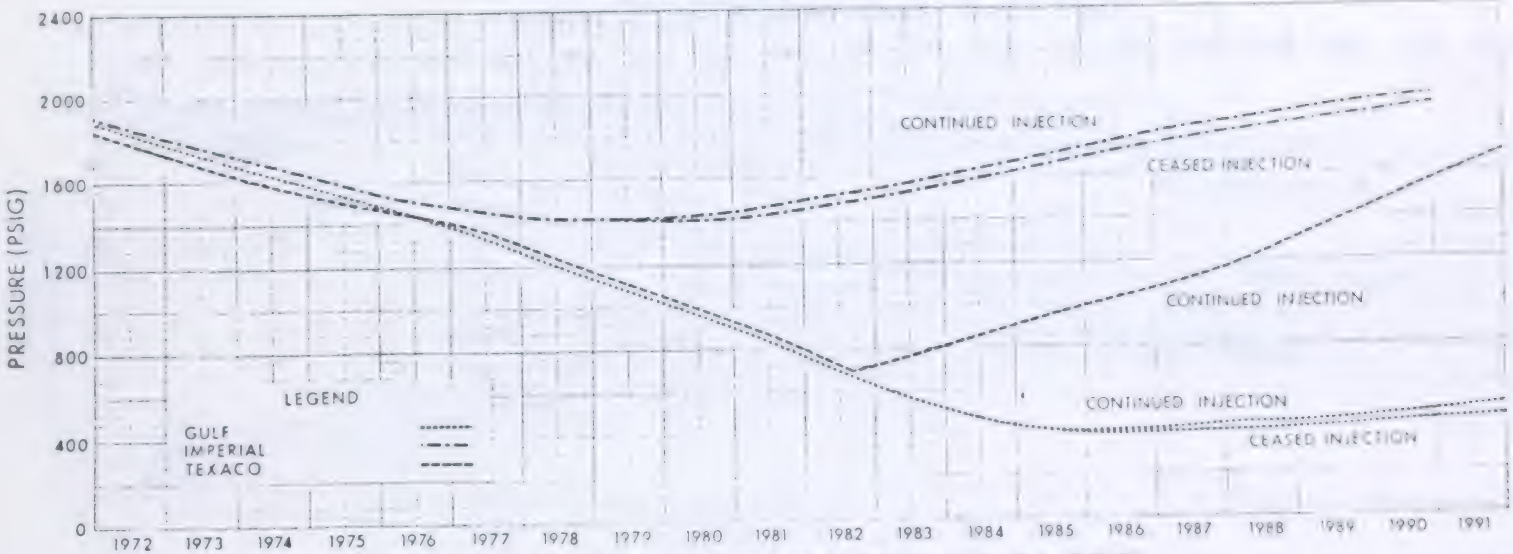


FIGURE 4.08-WESTEROSE SOUTH D-3A POOL
PRESSURE PRED NS

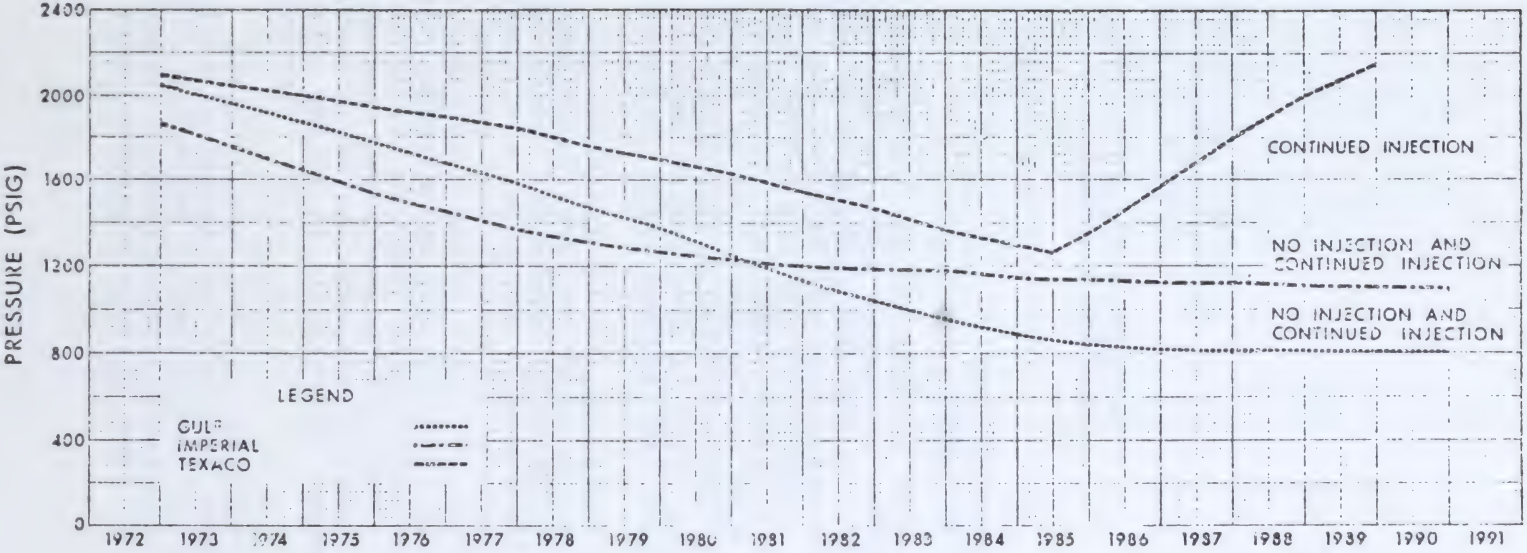


FIGURE 4.09 - HOMEGLEN RIMBEY D-3 POOL
PRESSURE PREDICTIONS

March 29 1972

Imperial Oil Limited
500 - 6 Avenue S. W.
Calgary 1, Alberta

Attention: Mr. W. B. Dingle
Regional Manager

Dear Sirs:

Primary Reserves - St. Albert -
Big Lake D-3A Pool

Subsequent to the Board's letter of November 29, 1971, concerning possible integrated operations in the Homeglen-Rimbey to St. Albert-Big Lake D-3 Reef chain of pools, the Board has reviewed the production and pressure performance of each of the pools in the trend. At the rates of oil and gas production from these pools in the last year or two, pressures in most pools in the chain have been declining despite substantial injection of water and gas for the purpose of pressure maintenance of three of the pools, namely, Acheson D-3, Leduc Woodbend D-3 and Wizard Lake D-3.

The recovery factors for pools with pressure maintenance approvals are based on enhanced recovery factors predicted for each scheme, and remain in effect as long as the terms of the approval are fulfilled. On the other hand, recovery factors for primary depletion pools in the chain have been determined over the years having regard for the flushing and volumetric sweep efficiencies and shrinkage effects that are likely to occur if the natural energy supporting the pools continues in the degree historically observed. The assignment of such primary depletion recovery factors is consistent with the Board's policy of oil reserves recognition throughout the Province.

Having regard for the acceleration in the rate of pressure decline in several of the pools, despite assistance from continued injection in nearby pools, the Board believes it is now necessary to reappraise the primary depletion recovery factors of large primary depletion pools in the reef chain.

The Board requests that Imperial Oil Limited submit a detailed prediction of the primary depletion reserves of the St. Albert-Big Lake D-3A Pool by October 31, 1972, assuming that the oil pools of the reef chain were not subject to injection of fluid for purposes of pressure maintenance after December 31, 1971, and that the gas pools of the chain were subject to subsisting contract rates of gas production. The Board suggests that the residual oil saturation for both water and gas displacement be taken as the same but should you wish to supply an additional case where the residual oil saturations are considered different the Board requests tha the evidence in support be fully documented.

Yours truly,

D. R. Craig, P. Eng.
Vice Chairman

DRC/ja

TABLE 4.11

RESIDUAL HYDROCARBON SATURATIONS

Company Pool	SORW			SORG			Critical Gas Plus Mobile Gas in the Oil Zone	Reduction of SORW by Trapped Gas
	Value Adopted	Lab Data	Performance Calculations	Value Adopted	Lab Data	Performance Calculations		
Imperial								
St Albert-Big Lake	0.257		0.257	Same as SORG				about 0.03
Gulf								
1) Glen Park	0.233		0.233					
2) Westerose	0.232	0.254 (72 imbibition tests) 0.218 (4 WF tests) Spray Lake Large Samples 0.166 (3 WF tests)	0.232	0.186	0.196 (4 GF tests) Spray Lake Large Samples 0.098 (4 GF tests)	0.232 using 0.140 using	0.093 0.056	
Texaco								
Bonnie Glen	0.354 to 0.329 depending on critical gas saturation	0.349 after 2 PV throughput	Substantiated interpreted lab data	0.245	0.362 after 2 PV throughput 0.206 after hundreds PV throughput	Substantiated interpreted lab data	0.10	0.025 maximum
Examiners								
All Pools	0.25			0.25			0.10	about 0.02-0.03

All values are fraction of total pore volume.
WF = Waterflood
GF = Gasflood

TABLE 5.01

COMPARISON OF PEAK MER CAPACITY

(Stock Tank Barrels Per Day)

Pool	Previous	Operator	Examiners
Mitsue Gilwood A	85,000	56,000	56,000
Pembina Cardium: Project Areas	-	125,300	125,300
Total Pool	171,000	-	135,000
Pembina Keystone Belly River B	5,500	13,700	10,000
Pembina Keystone Belly River C	-	6,800	2,500
Pembina Keystone Belly River M	-	1,500	1,300
Redwater D-3	180,000	165,000	165,000
Willesden Green Cardium A	35,500	22,700	16,000
Bantry Mannville A	-	7,075	7,000

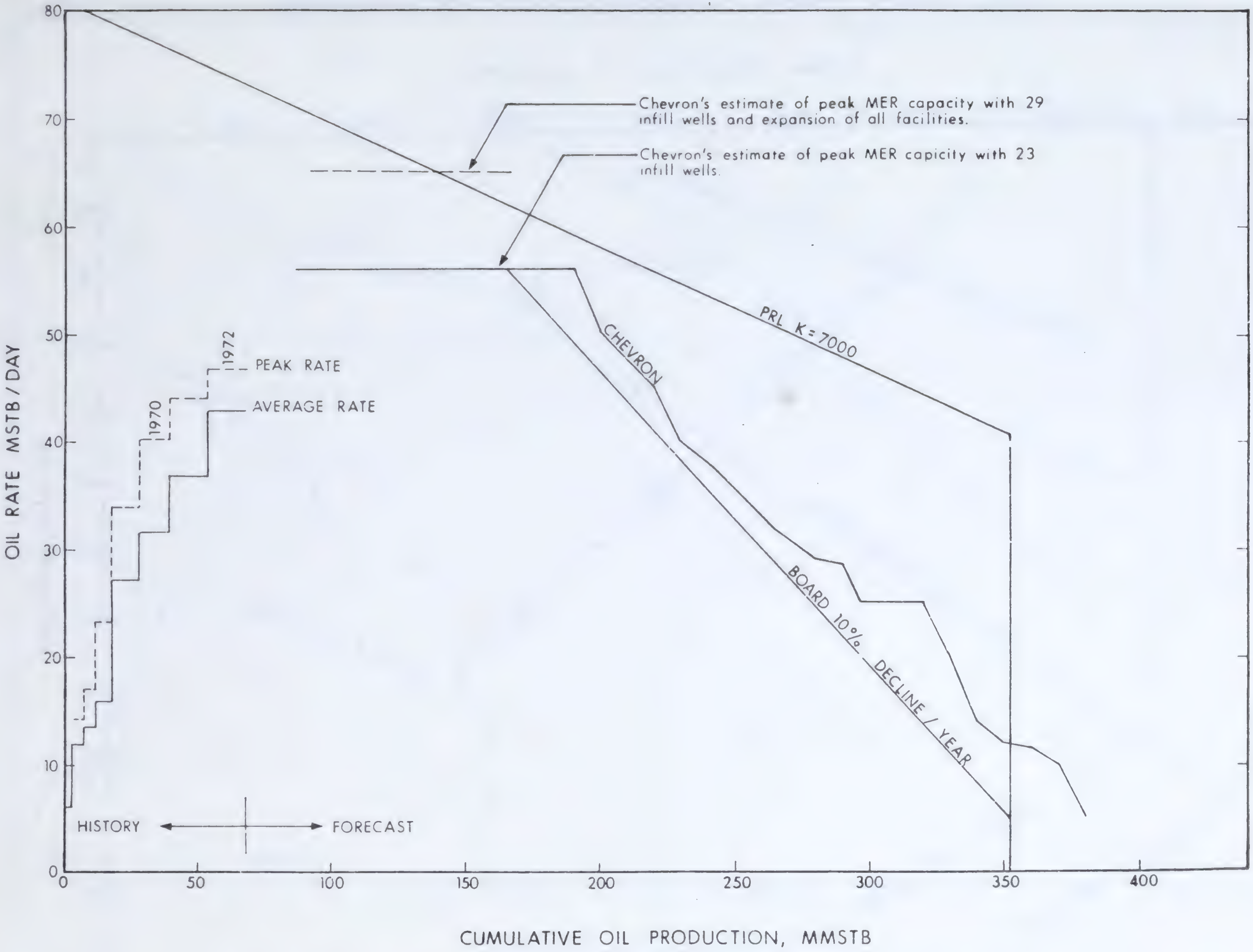


FIGURE 5.01 MER CAPACITY FORECAST - MITSUE GILWOOD A POOL

TABLE 5.01

COMPARISON OF PEAK MRR CAPACITY
(Stock Tank Barrels Per Day)

Pool		Previous	Operator	Examiners
Mitsue Gilwood A		85,000	56,000	56,000
Pembina Cardium:	Project Areas	-	125,300	125,300
	Total Pool	171,000	-	135,000
Pembina Keystone	Belly River B	5,500	13,700	10,000
Pembina Keystone	Belly River C	-	6,800	2,500
Pembina Keystone	Belly River M	-	1,500	1,300
Redwater D-3		180,000	165,000	165,000
Willesden Green Cardium A		35,500	22,700	16,000
Bantry Mannville A		-	7,075	7,000

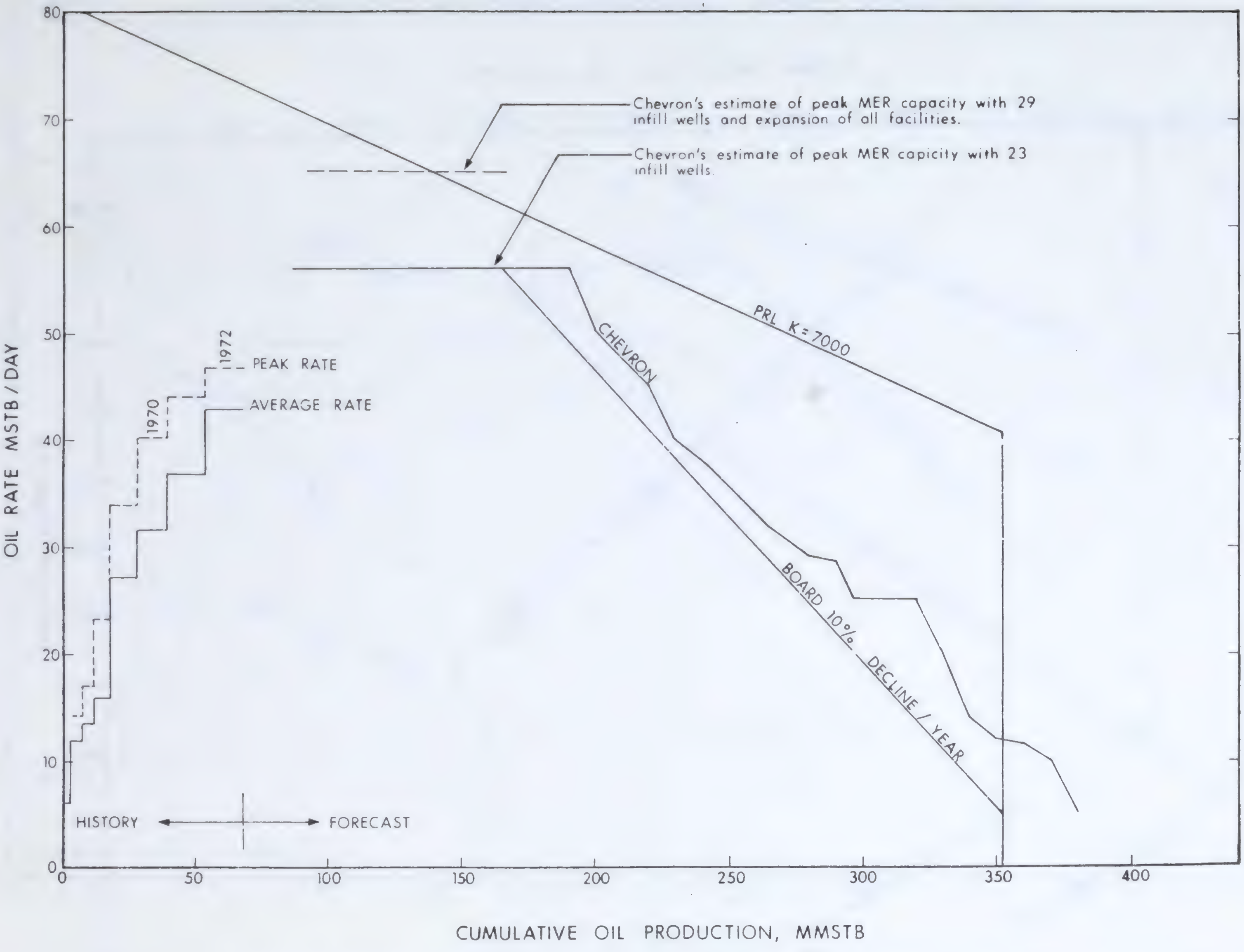


FIGURE 5.01 MER CAPACITY FORECAST - MITSUE GILWOOD A POOL

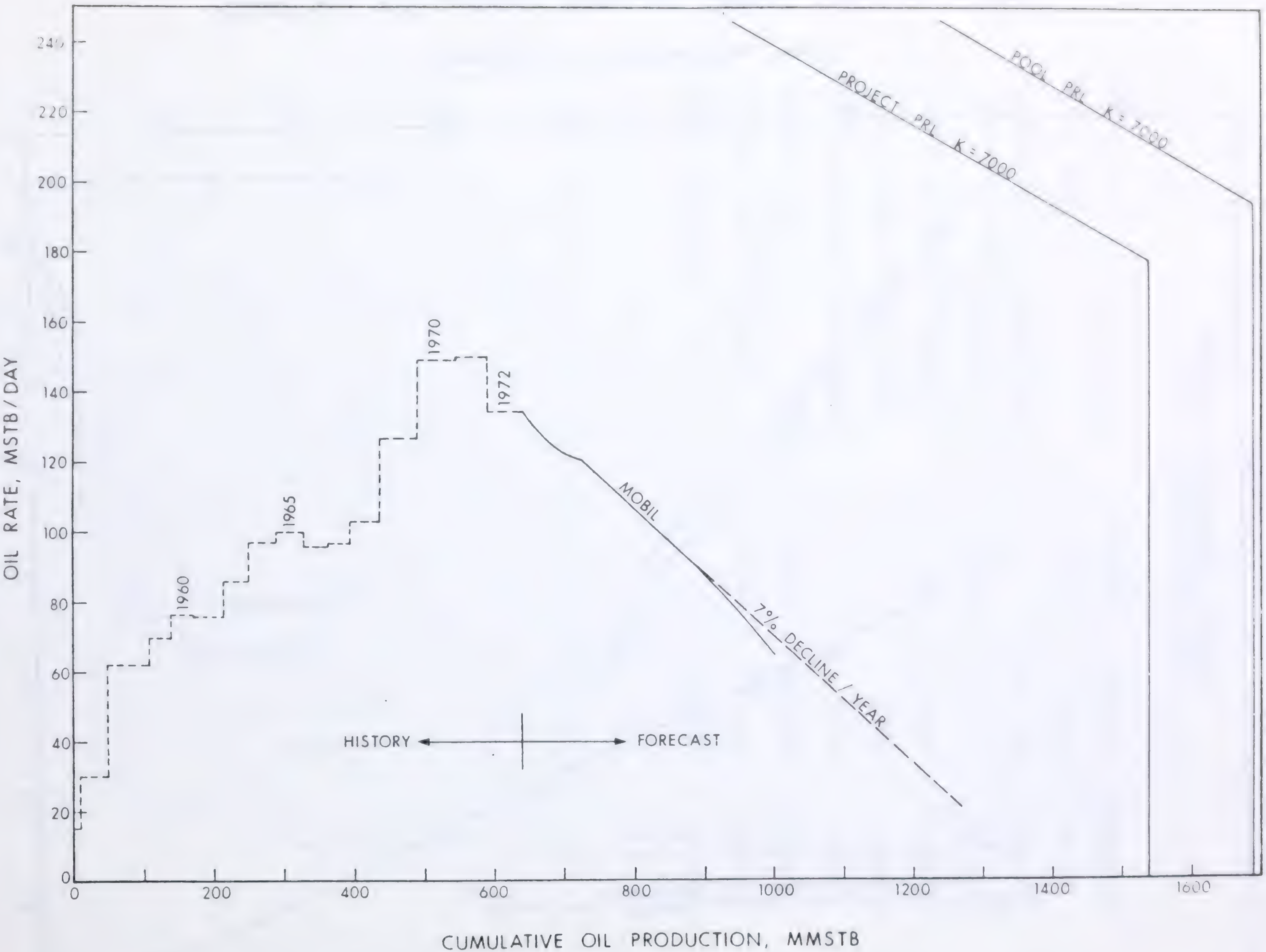


FIGURE 5.02 MER CAPACITY FORECAST - PEMBINA CARDIUM POOL

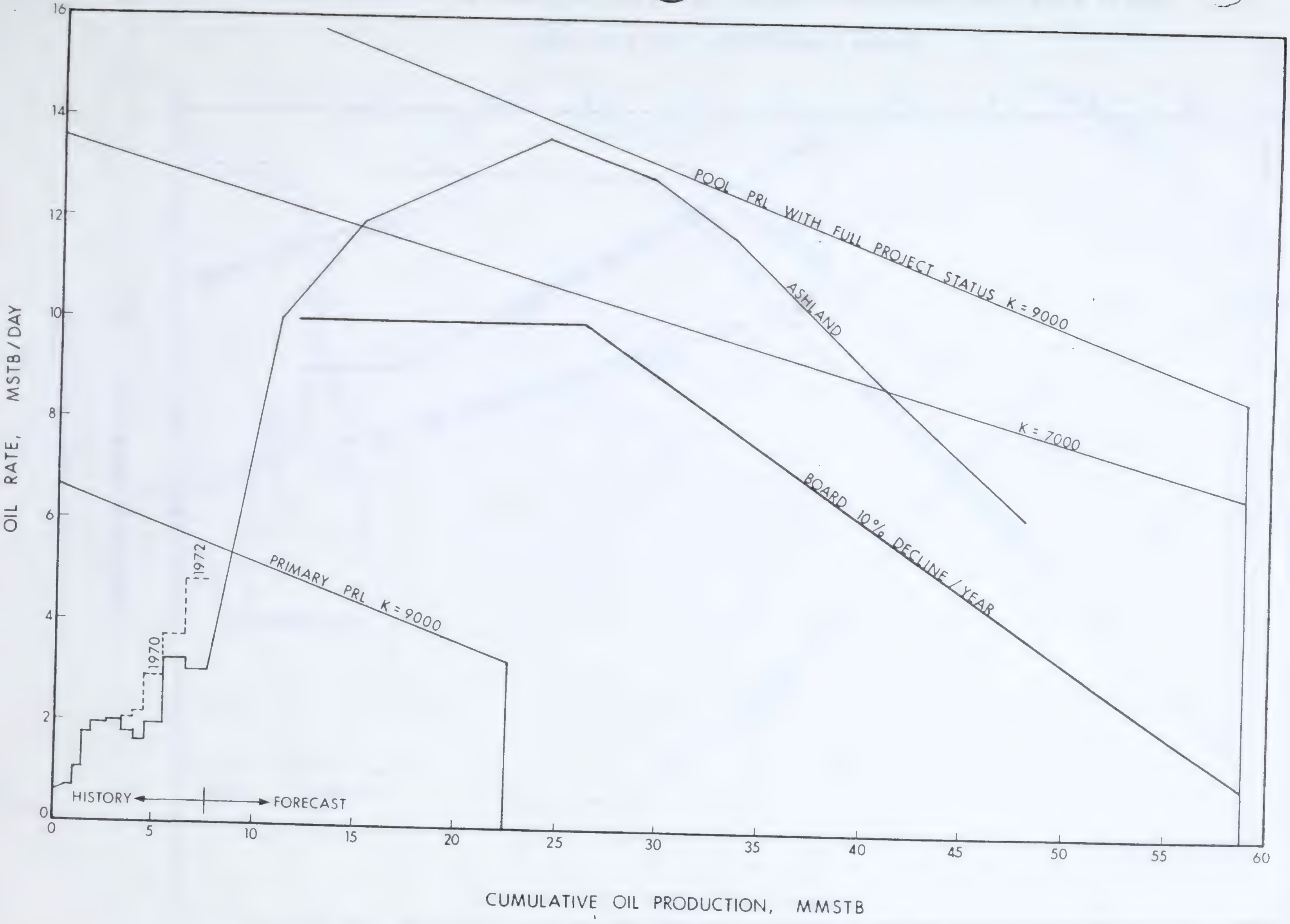


FIGURE 5.03 MER CAPACITY FORECAST - PEMBINA KEYSTONE BELLY RIVER B POOL

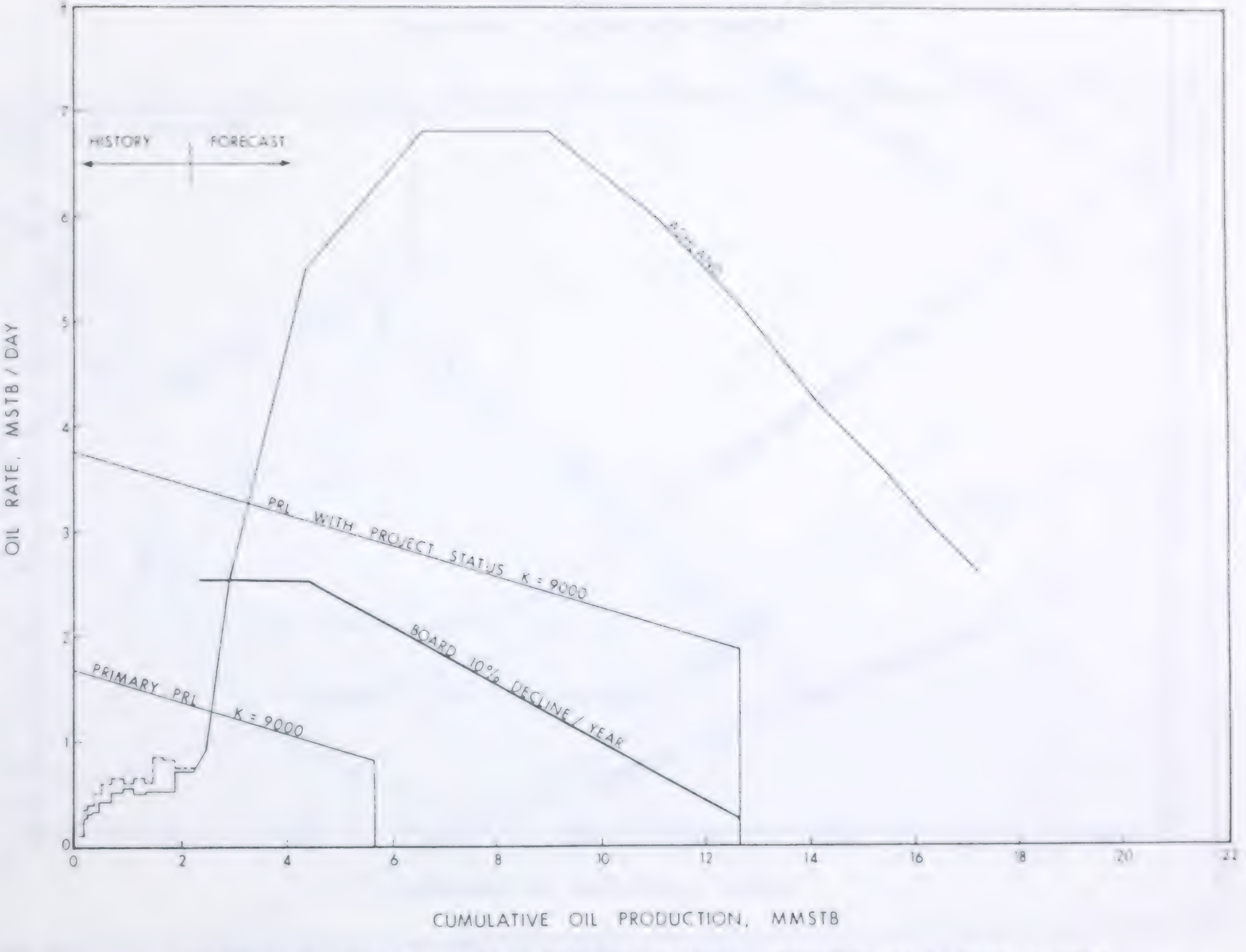


FIGURE 5.04 MER CAPACITY FORECAST - PEMBINA KEYSTONE BELLY RIVER C POOL

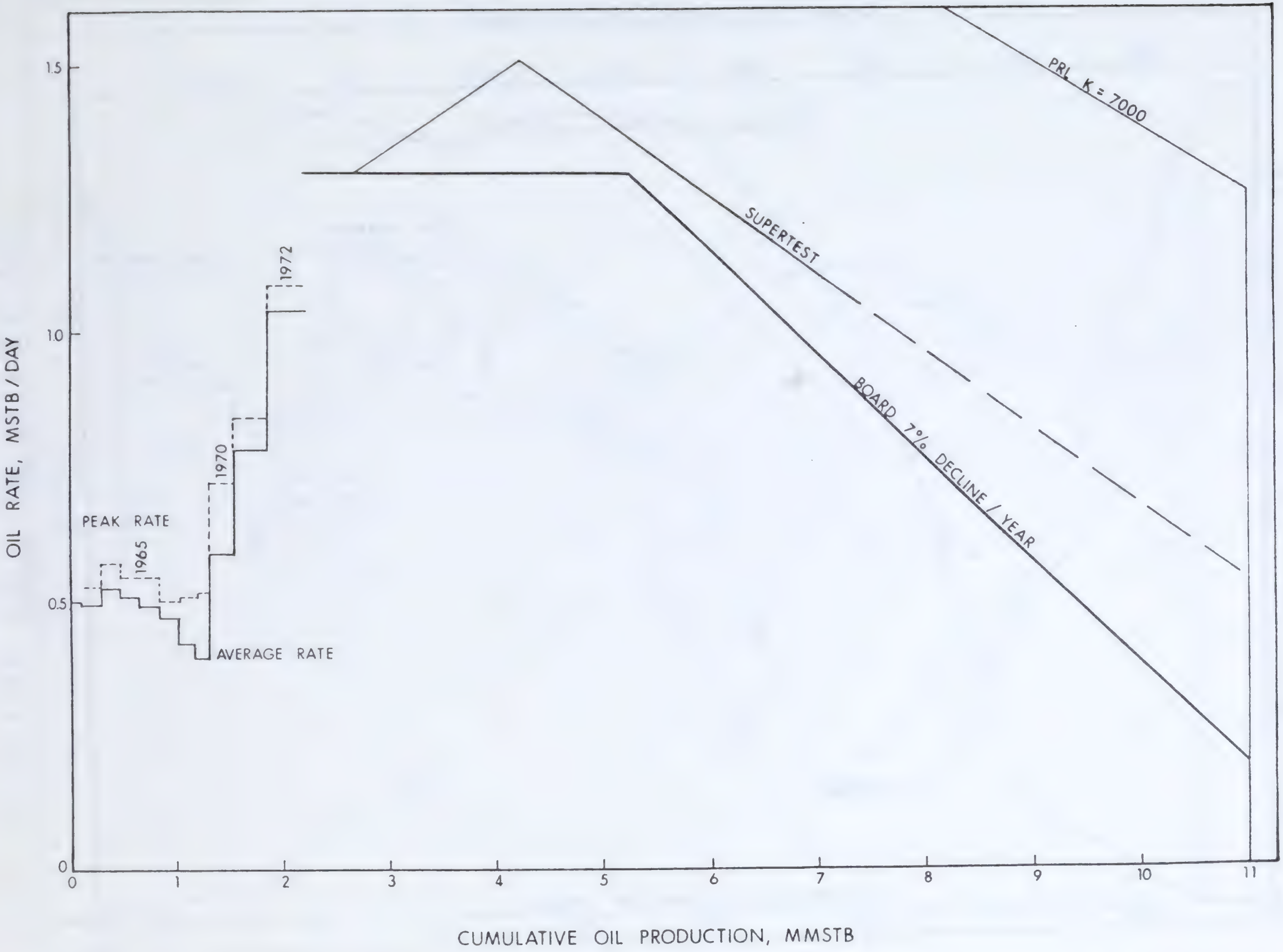


FIGURE 5.05 MER CAPACITY FORECAST - PEMBINA KEYSTONE BELLY RIVER M POOL

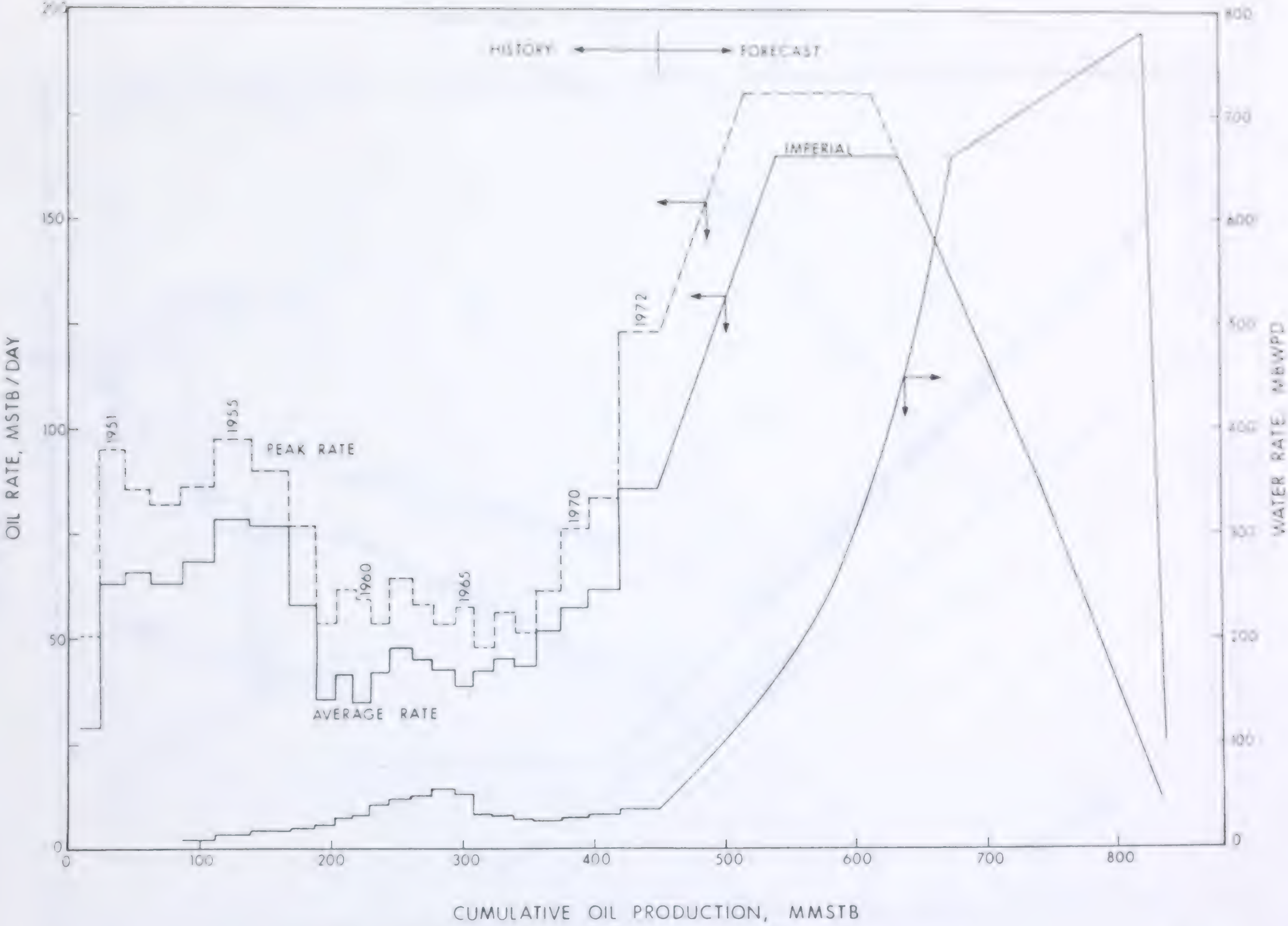


FIGURE 5.06 MER CAPACITY FORECAST - REDWATER D-3 POOL

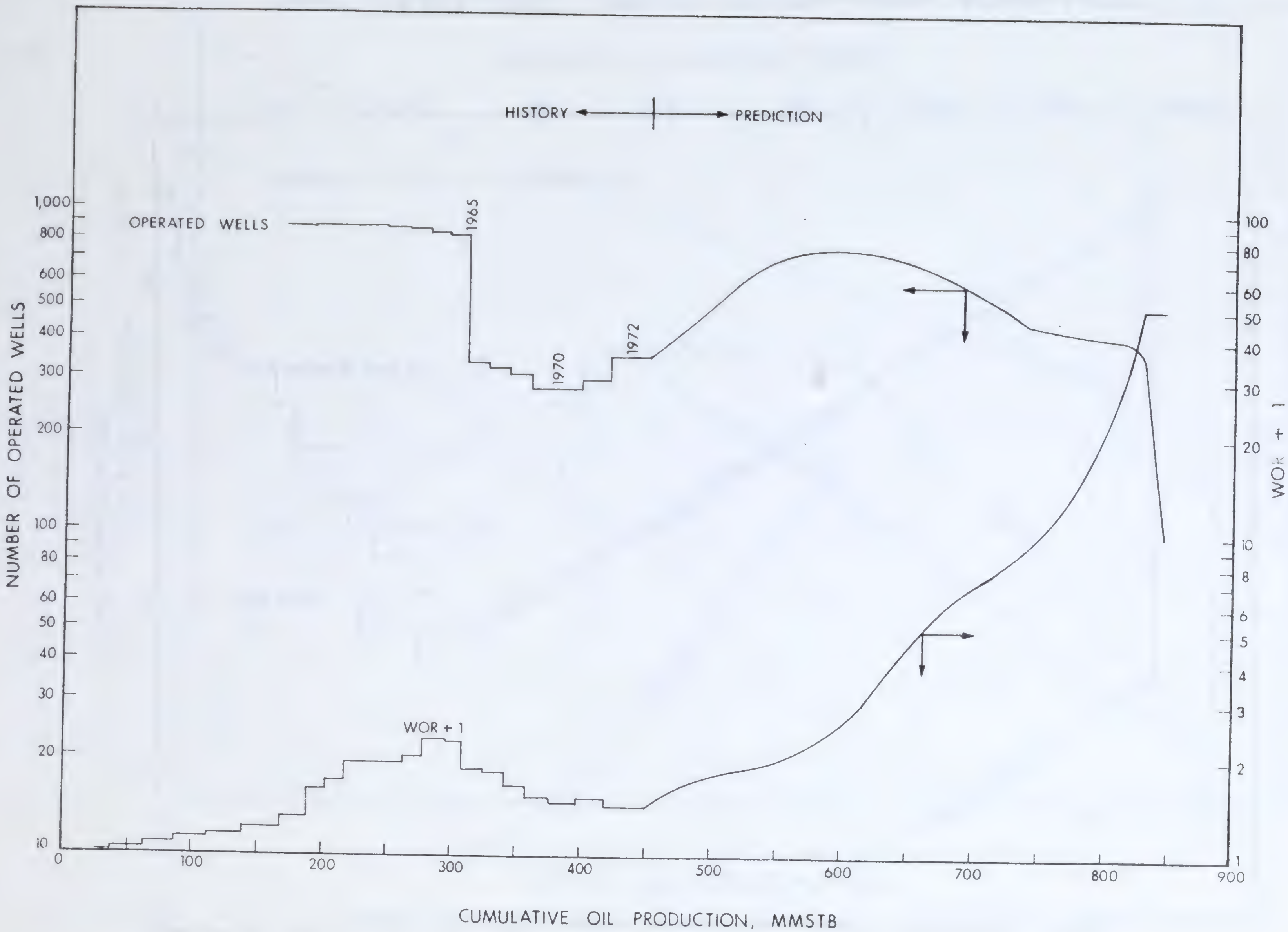


FIGURE 5.07 POOL PERFORMANCE DATA - REDWATER D-3 POOL

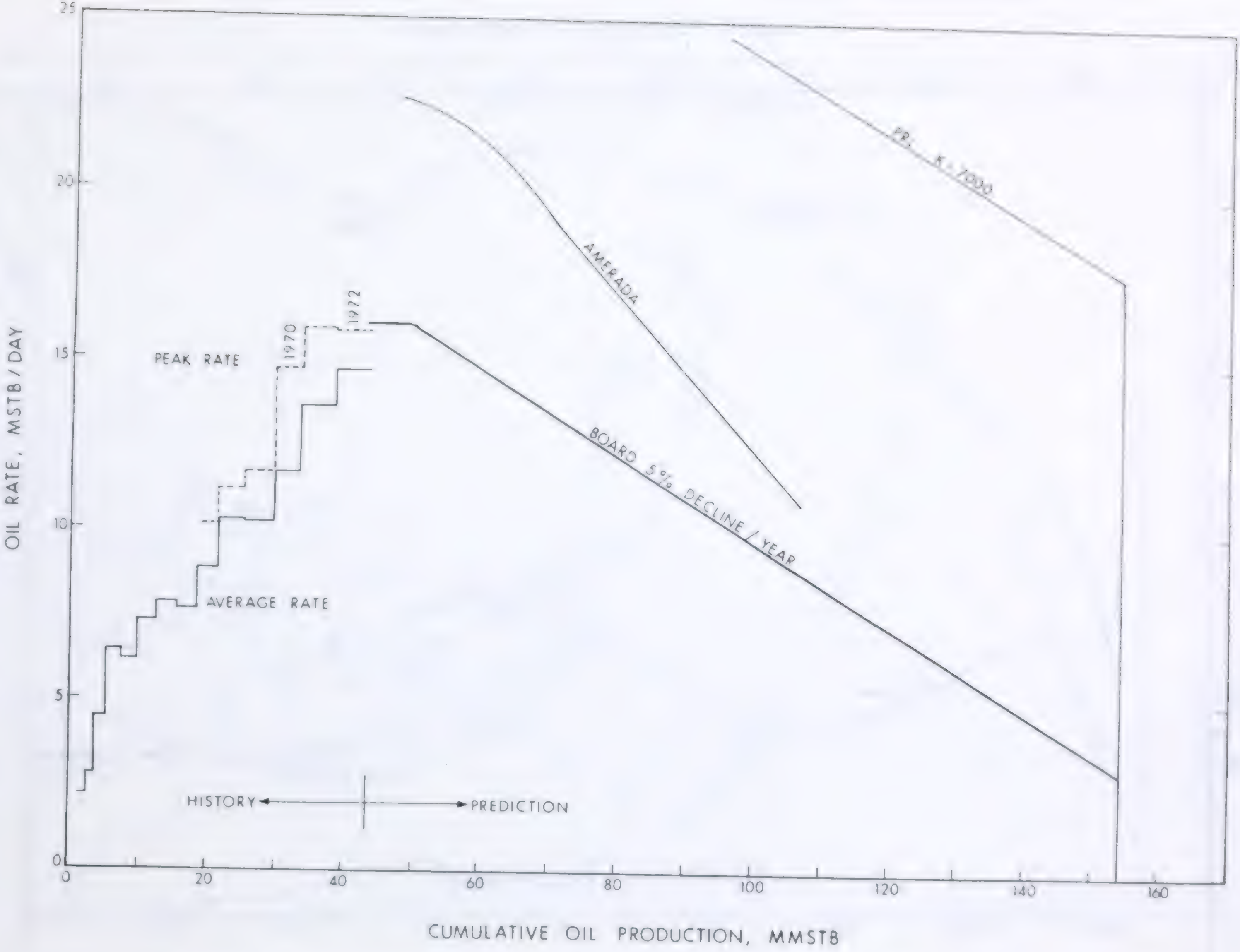


FIGURE 5.08 MER CAPACITY FORECAST - WILLESDEN GREEN CARDIUM A POOL

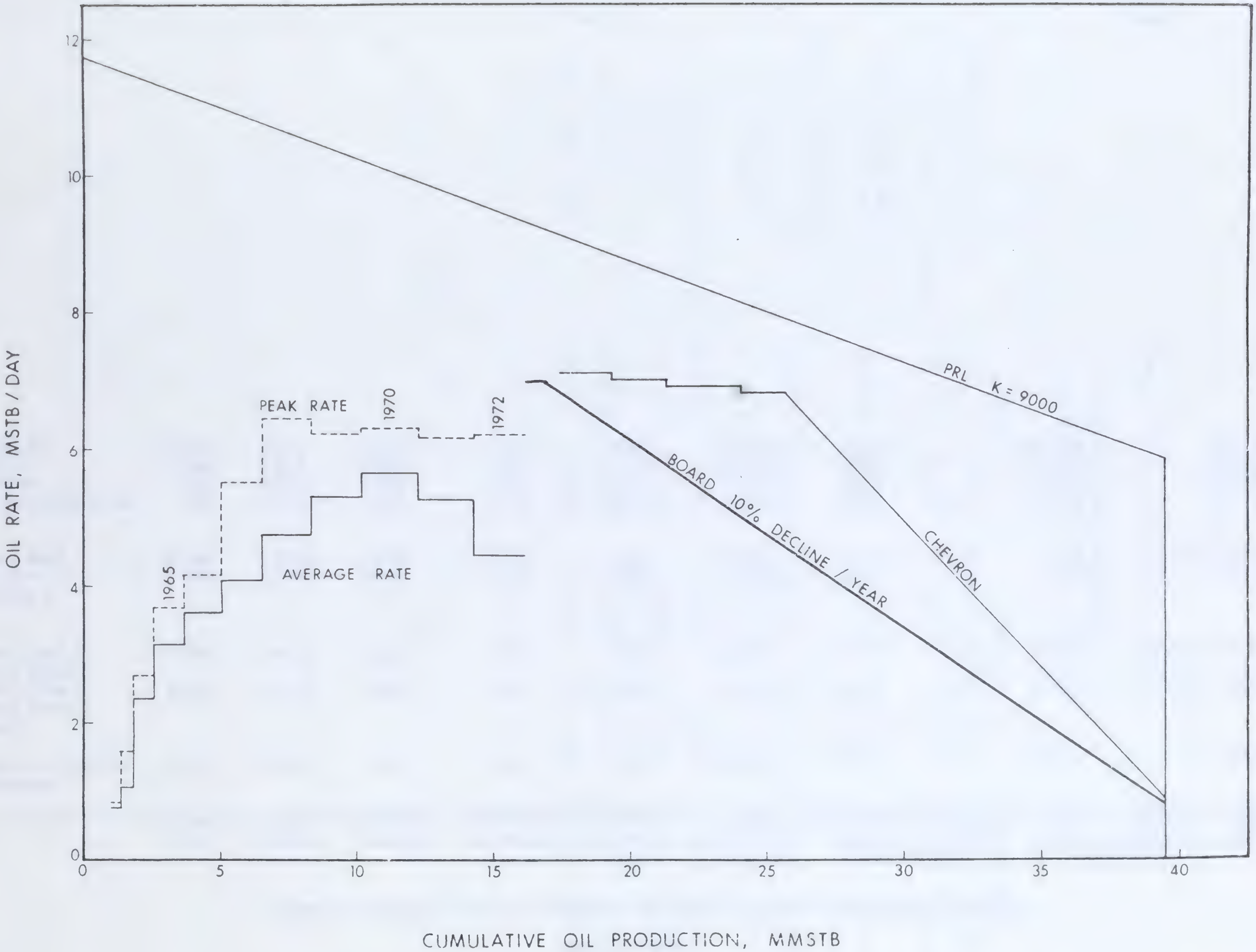


FIGURE 5.09 MER CAPACITY FORECAST - BANTRY MANNVILLE A POOL

TABLE NO. 4.01

EXAMINERS RECOMMENDED RESERVE FACTORS - POOLS AT JANUARY 15, 1973 RESERVES HEARING

Pool		AREA (Acres)	PAY THICKNESS (Feet)	POROSITY (Fraction)	WATER SATURATION (Fraction)	OIL SHRINKAGE (st/bbl)	INITIAL OIL IN PLACE (MSTB)	POOL RECOVERY PRIMARY (Fraction)	POOL RECOVERY ENHANCED (Fraction)	RECOVERABLE OIL PRIMARY (MSTB)	RECOVERABLE OIL ENHANCED (MSTB)	RECOVERABLE OIL TOTAL (MSTB)
MANNVILLE-BLAIRMORE												
Bellshill Lake Blairmore	-	5,780	(28.5)	0.255	0.85	0.93	258,000	<0.24	-	60,000	-	60,000
BEAVERHILL LAKE												
Carson Creek North Beaverhill Lake A	-	9,405	(30.7)	0.080	0.87	0.55	84,600	0.15	0.30	12,700	25,400	38,100
Carson Creek North Beaverhill Lake B	-	16,220	(47.8)	0.089	0.85	0.60	273,000	0.16	0.31	43,700	84,900	128,000
GILWOOD												
Nipisi Gilwood C												
Primary Area	-	1,115	(11.3)	0.120	0.65	0.83	6,330	0.20	-	1,270	-	1,270
Waterflood Area	-	4,190	(11.3)	0.120	0.65	0.83	23,800	0.20	0.20	4,760	4,760	9,520
LEDUC D-3												
St. Albert Big Lake D-3A	-	249	142.0	0.110	0.94	0.82	23,300	0.72	-	16,800	-	16,800
Glen Park D-3A	-	427	129.0	0.097	0.93	0.76	29,300	0.72	-	21,100	-	21,100
Westerose D-3	-	1,890	185.0	0.094	0.93	0.67	159,000	0.67	-	107,000	-	107,000
Bonnie GlenD-3A	-	7,500	181.9	0.095	0.94	0.68	643,000	0.69	-	444,000	-	444,000

TABLE 6.02

Comparison of Oil In Place and Recoverable Reserves

(Thousands of Stock Tank Barrels)

Pool	Previous N	Previous U	Operator N	Operator U	Examiners N	Examiners U
Bellshill Lake Blairmore	238,000	80,000	253,520	96,042	258,000	60,000
Carson Creek North Beaverhill Lake A	86,600	39,000	80,867	41,566	84,600	38,100
Carson Creek North Beaverhill Lake B	257,000	121,000	305,397	173,160	273,000	128,000
Nipisi Gilwood C	27,800	10,500	34,800	12,420	30,100	10,800
St. Albert Big Lake D-3A	23,300	14,400	23,500	16,300	23,300	16,800
Glen Park D-3A	29,300	19,600	28,809	20,850	29,300	21,100
Westerose D-3	159,000	111,000	159,000	120,850	159,000	107,000
Bonnie Glen D-3A	613,000	423,000	657,138	414,175	643,000	444,000

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-5
Application No. 6676

TRANSMISSION LINE - HIGH RIVER AREA

INTRODUCTION

The subject application was made under sections 9 and 11 of The Hydro and Electric Energy Act by Calgary Power Ltd. for a permit to construct and a licence to operate two electrical transmission lines in the High River Area. The applicant proposes to rebuild and relocate on new routes portions of its present lines designated as 14 Line and 16 Line. The new portion includes a double circuit electrical transmission line running from the Calgary Power substation, designated as 65S, in the Northeast quarter of Section 11, Township 19, Range 29, West of the 4th Meridian, due east to a point 800 feet east of the westerly limits of the Southwest quarter of Section 17, Township 19, Range 28, West of the 4th Meridian, where the 16 Line will be connected with an existing line and continue east. From the point where the double circuit line connects to the existing line, one line of the double circuit, which is designated as 14 Line, will run in a southerly direction from that point, to a point on the road allowance adjoining the Southwest quarter of Section 30, Township 18, Range 28, West of the 4th Meridian, where it will connect with an existing line.

The application was heard at the offices of the Board, in Calgary, Alberta, on January 8, 1973, by Mr. Vernon Millard, Vice Chairman, and Mr. J. I. Strong, P. Eng., Board Member.

The following appeared at the hearing:

	Represented by	Witnesses
Applicant:		
Calgary Power Ltd.	R. J. Pitt H. M. Kay	E.J. MacLeod, P.Eng. S. Winning, P. Eng.
Interveners:		
Town of High River		A.Fullerton
W. G. Milne		W. G. Milne
Phyllis M. Robertson	R. J. Gibbs, Q.C. B. Halliday	

Board Staff:

C. J. Goodman, P. Eng.
A. L. McLarty, Assistant Board Solicitor

THE BACKGROUND TO THE APPLICATION AND THE APPLICATION

The purpose of constructing portions of 14L and 16L transmission lines on new routes, as outlined by the applicant, is to replace what are very old lines, parts of which date back to the 1920's and which have surpassed their normal useful life. In addition the applicant proposes to originate both 16 Line and 14 Line at the new substation 65S, in order to provide better and more reliable service to the applicant's customers.

As originally constituted, 14 Line and 16 Line radiates from a substation, designated as 10S, and which is also a town distribution substation located in the heart of the Town of High River. The 14 Line extends in a southerly direction to feed the areas of Cayley, Nanton, and north to the areas of Alderside and Okotoks. The 16 Line also originates from the 10S substation and extends through the Town of High River, in an easterly direction to feed the Vulcan and Blackie Areas.

It is the policy of the Board to publish notice of an application for a permit to construct a transmission line for which the applicant has not acquired the right of way. Following this policy, the Board advertised the subject application for objections by a Notice issued on October 30, 1972. The Board, as a result of the said Notice, received objections from several land owners in the area of the proposed transmission lines.

Objection by letter, dated November 17, 1972, was received from Mr. A. F. Bishop and Mr. W. Koopman, but no reasons for protesting were advanced. By letter of the same date objection was received from Mrs. A. F. Bishop, F. L. Campbell and Ruth Maccoy, none of which offered reasons for objection.

An objection to the application, dated November 20, 1972, was also filed on behalf of Mrs. Phyllis Marie Robertson who protested both the procedural aspects of the application as well as the proposed routes of the transmission lines.

As a result of the objections so filed, the Board decided to convene a public hearing in order to consider, determine and resolve the issues concerning the application. A notice of the hearing was issued on November 30, 1972 and copies of the notice were mailed to all known owners and occupants of the lands adjoining the proposed routes of the transmission lines outside the town of High River. In addition, the notice was published in major Alberta newspapers and The High River Times.

Pursuant to the notice of hearing, interventions were received from Mrs. Phyllis Marie Robertson, Mr. W. G. Milne and the Town of High River. Of the original objectors only Mrs. Robertson attended or was represented at the hearing.

DEFINITION OF THE ISSUES

The Board is required under the terms of The Hydro and Electric Energy Act to secure safe and efficient practices in the public interest in the transmission and distribution of electric energy.

The main issue is whether the location of the proposed transmission lines is satisfactory having regard for the interests of the land owners, the Town of High River and the needs of the utility company to serve the public interest in a safe and efficient manner.

VIEWS OF THE APPLICANT

The applicant's submission outlines the relative age of the transmission lines presently in existence and the need for more reliable and higher capacity facilities. The applicant had hoped to complete the construction of the lines before the peak load requirements during the winter months of 1972-73.

Calgary Power stated, that in selecting the proposed route, it took into consideration a number of relative factors, including the growing need for electricity within the Province of Alberta, the width of the required right of way, the environmental aspects of the proposed transmission lines, the interests of the public and of private property owners as well as the economic factors to be considered in connection with the construction of the line.

The applicant stated that the development of Line 16 and Line 14 was a part of its overall plan to upgrade service to the High River area, which in turn would improve the service between High River and Vulcan and High River and Stavely. The first step in this plan was completed by the construction of a new 138 KV feeder line from Calgary to a new substation called 65S, located north-west of the Town of High River and by increasing the primary supply voltage from 69 KV to 138 KV. The locations of the substation 65S and the proposed 16 Line and 14 Line are shown on Appendix 1.

The subject application represents the next stage of development of the overall plan and involves the construction of two lines commencing at the 65S substation, each equipped with its own protective devices and with each line serving a separate area; in the one case High River to Vulcan, in the other High River to Stavely. The Town of High River would continue to be served through the 10S substation. The applicant indicated that an additional feeder substation, to serve the Town, would ultimately be constructed at the east side of the Town and would be connected to the proposed new 14 Line.

The applicant, in stressing the need for the proposed new lines pointed out that the load was growing in the area at the rate of about 10 per cent per annum and the reliability of the service to the Town and its surrounding area would be improved by separating the circuits from 65S substation instead of the one line connecting 65S to 10S as it presently exists, with both 16 Line and 14 Line fed from 10S. The applicant also pointed out that in the case of an emergency in High River that either or both lines could feed back from Vulcan and Stavely to maintain essential electrical services in High River.

With respect to the route selected for 16 Line, the applicant justified that route on the basis that the part of the original 16 Line, located in the Town was to be moved at the request of the Town of High River; the new route was the shortest possible between the two connecting points of the proposed line; the line would be wholly constructed on public road allowance, except for that portion of the original road allowance lying north of and adjoining the north boundary of Section 8, Township 19, Range 28, West of the 4th Meridian, which lies to the west of the intersection of the said road allowance with the westerly limits of the surveyed roadway, and as shown on Plan 3792K owned by Mrs. Robertson; the proposed river crossing was the most accessible for the purpose; the route would affect the least number of land owners in the vicinity and the route would be away from the populated areas of the Town of High River.

With respect to the route selected for 14 Line, the applicant indicated that such route would be advantageous in that it would no longer extend through the Town of High River; the line would be entirely constructed on public road allowance, the route would affect the least number of property owners in the area and the route was the shortest route between the two possible connection points.

With respect to alternative routes, the applicant stated that other possible routes lacked the feasibility of the routes proposed. The applicant stated, that in its opinion, if 16 Line were to be relocated from its present location then the route selected was the only feasible route for that new line.

With respect to alternative routes proposed for 14 Line, the applicant stated that it had considered a north-south route west of the Town of High River, but that such route would conflict with future potential park usage of the river bank area and in addition, that such a route would result in the cutting of mature trees and a more difficult river crossing for the line. The applicant also considered a route one mile east and parallel to the route proposed, but such was not considered to be feasible inasmuch as it would add considerable length to the line, would interfere with an aircraft landing strip located in the Southeast quarter of Section 8, Township 19, Range 28, West of the 4th Meridian and would pass directly through a new residential development located on the east side of the section line. A third alternative considered by the applicant, was that of routing the line through the half section line immediately east of the proposed route. This latter alternative was dismissed by the applicant as not being feasible, inasmuch as the route would be located almost wholly on private property and in addition to being considerably longer than the route proposed would also be an additional hazard to the aircraft landing strip in the Southeast quarter of Section 8.

Calgary Power have, subsequent to the hearing of their application, indicated to the Board that they were willing to consider at further length the proposed north-south route of 14 Line east of the Town, this consideration to be carried out in conjunction and co-operation with the Town of High River.

VIEWS OF THE INTERVENERS

Of the interveners who appeared at the hearing, the Town of High River and Mrs. Robertson were principally interested in the route of the 14 and 16 Lines. Mr. Milne who also intervened at the hearing was to some degree concerned as to the routes of the line but only from the point of view that the lines were visually objectionable.

The Town of High River submitted that growth of the town, projected on the basis of a long range planning study, was limited in the direction in which it might grow. A preliminary analysis of the study indicated that future expansion of the town would be mainly in an easterly direction. Accordingly, the town is concerned that if such growth should occur in the future, the location of 14 Line as proposed by the applicant would be at or near the future centre of the Town of High River. Consequently, the Town of High River requested further consideration be given to the route of 14 Line inasmuch as the present route would traverse the town's present potential expansion area. The Town, however, stated that the route proposed by the applicant would be more acceptable than a route to the west of the Town.

Mrs. Robertson's primary objection to the proposed route of 16 Line related to its location on the east-west road allowance on the north side of Sections 12 and 7 and in particular to the small portion north of section 8 now owned by Mrs. Robertson which includes a river crossing and is an area which is considered as potential sub-dividable land. It was also put forth on behalf of Mrs. Robertson that the present location of 16 Line and 14 Line need not be relocated and in fact such relocation was not justified under the circumstances and that even if such relocation were justified insufficient consideration had been given to the examination of alternate routes for the relocation of these particular lines.

Mr. Gibbs, counsel for Mrs. Robertson, also raised the question of burying the transmission line or a portion of it through his client's land as another possible alternative that should have been considered by the applicant.

An intervention filed by Mr. Milne consisted of an objection in a general form, not involving any particular portion of the route or aspect of the application. Mr. Milne's objection was that the applicant had not given sufficient consideration to the "visual chaos" that would be created by the intersection of these various lines. Mr. Milne suggested that the application should not be granted in the absence of more consideration and study being devoted to the design and visual appearance of not only this but all transmission lines within the Province.

VIEWS OF THE BOARD

The Board after hearing the evidence of the applicant is satisfied that due to the age of the existing lines, the rate of load growth in the area and the reliability of the lines, an upgrading of transmission facilities in and around the Town of High River would be in the public interest.

The Board agrees with the applicant that the reliability in servicing not only the Town of High River but the adjoining areas of Vulcan and Stavely will be improved by originating the 16 Line and the 14 Line at the 65S substation, with a separate lead to the 10S substation to serve the Town of High River. The Board is of the view that interrupting service due to a faulty and unreliable system becomes a serious matter in a growing and expanding community that depends upon electricity for much of its energy requirements.

The Board considers it advisable to assess the location of the 16 Line and 14 Line separately and gives its views accordingly.

16 Line

The route of 16 Line, to serve the Vulcan area, selected by the applicant, as shown on Appendix 1, hereto attached, would run from the 65S substation east to the existing 16 Line located at a point on the road allowance between Sections 8 and 17, marked as point "A" on Appendix 1, and is the most direct route. The route, with the exception of the most easterly 800 feet, owned by Mrs. Robertson, is located on a surveyed east-west road allowance and in total is slightly over two miles in length. The route also crosses the Highwood River on this same property owned by Mrs. Robertson. The Board has examined the plan outlined in Appendix 1 and apart from using the present route through the centre of the Town of High River, any alternate route would appear to be longer, would also involve a river crossing and would affect more land owners. Furthermore, the proposed route is in compliance with the request of the Town of High River that this line be removed from the Town's built up area.

While the question of burying transmission lines was raised by Mr. Gibbs on behalf of Mrs. Robertson, no evidence was given at the hearing on this matter. The Board has considered the possibility of burying the transmission line on Mrs. Robertson's property but notes that the cost of undergrounding transmission lines is many times the cost of overhead construction. To bury a short length to serve one owner could not be justified in the public interest and would become a very expensive precedent. Furthermore in this particular instance to bury a line under a river creates a hazard as well as despoiling, to some degree, the river banks.

The Board acknowledges that the proposed location of the transmission line could affect the value of Mrs. Robertson's property through its impact on subdivision planning and possible sterilization of the land adjacent to the line. These however, are matters beyond the jurisdiction of this Board.

After due consideration of the foregoing matters the Board concurs in the route proposed by the applicant as the most feasible location for the 16 Line.

14 Line

The 14 Line is proposed to connect the 65S substation north-west of the Town of High River with an existing line located to the south-east of the Town, and serving the Stavely area, by bypassing the existing 10S substation and the developed area of High River. The 14 Line is proposed to be constructed on the same poles as the proposed 16 Line from the 65S substation to a point on the east-west road allowance east of the intersection of the south-east quarter of Section 17 and the north-west quarter of Section 8, Township 19, Range 28, West of the 4th Meridian, marked as point "A" on Appendix 1. The combining of the 14 Line and 16 Line on the same poles and using the same right of way is satisfactory to the Board. It eliminates a line on an additional right of way in order to cross to the east side of the Town and also provides a measure of economy in the construction of this line. From the point, marked as "A", on Appendix 1, the route then turns south on the registered road allowance, on the west side of Section 6 and follows this road allowance to where it meets Highway 2A and then follows Highway 2A to meet the existing 14 Line at a point on the north-south road allowance south of the mid-point of Section 30, Township 19, Range 28, West of the 4th Meridian, marked as point "B" on Appendix 1, hereto attached.

The Board notes that the applicant has considered several alternate routes for the 14 Line, all of which by-pass the Town. The Board accepts the view of the applicant that an alternate route south along the west side of the Town of High River would be unacceptable, as it involves a river crossing through a potential park area and the cutting of mature trees.

The Board also notes that several alternate routes have been considered on the east side of the Town and these were rejected in favour of the proposed route because of interference with an aircraft landing strip, a new residential development, increased cost and affecting more people.

In view of the concern of the Town of High River, regarding the location of 14 Line, and the applicant's statement that it would be prepared to give further consideration to the location of this route, by consulting with the Town, the Board has decided to defer a decision on the north-south line located between points "A" and "B" as outlined in Appendix 1.

DECISION

The Board upon considering the application and the evidence submitted at the hearing has decided to approve the application for the construction of Line 16 and the east-west portion of Line 14 as a double circuit transmission line to be located between Substation 65S and point "A" as shown on the attached Appendix 1.

The Board defers a decision on the construction of Line 14 between points "A" and "B" in order that the applicant and the Town of High River shall have the opportunity to review this location.

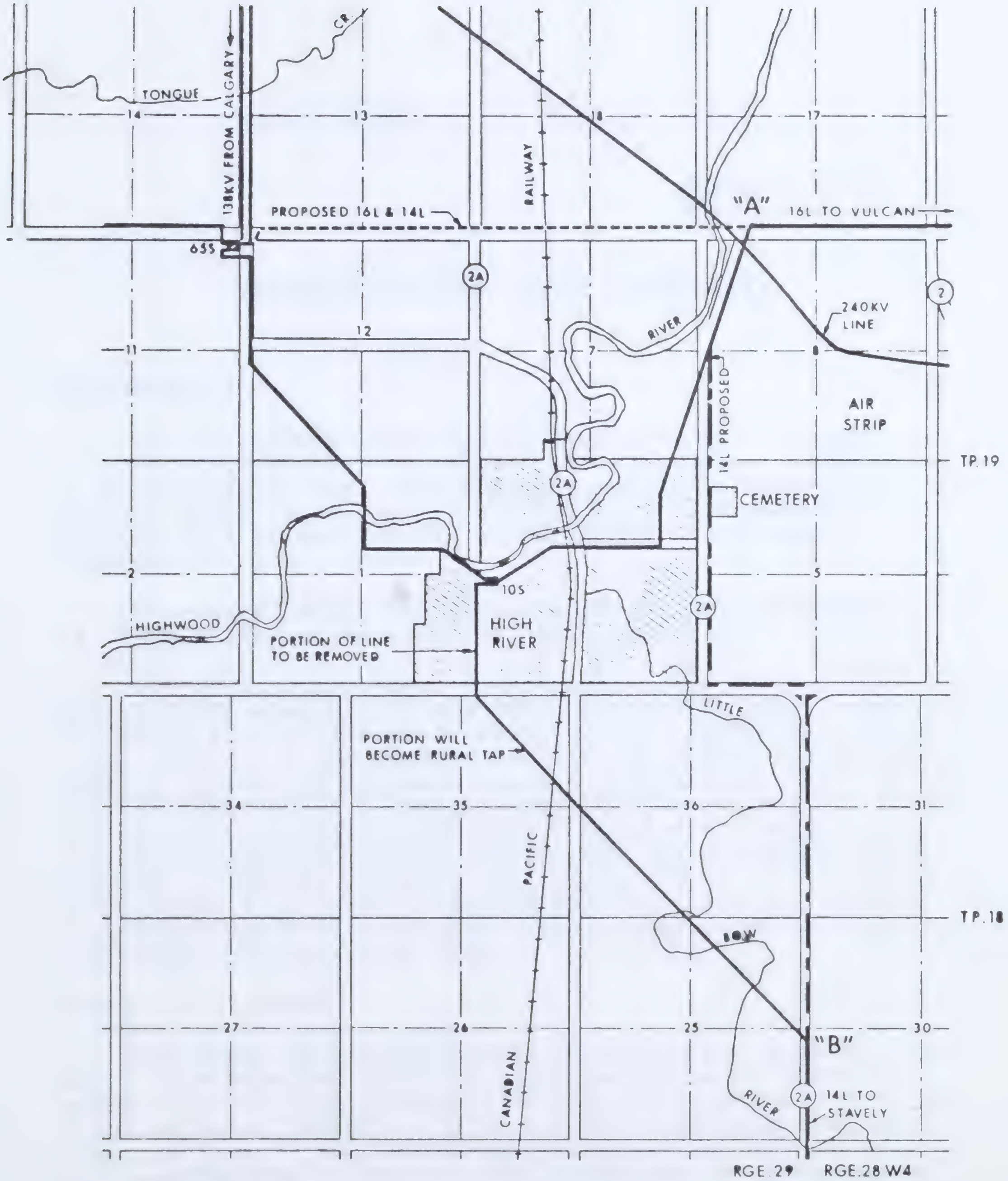
ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
March 13, 1973

Attachment



PROPOSED 23KV TRANSMISSION LINE ROUTES

———— CALGARY POWER LTD. EXISTING LINES
— — — CALGARY POWER LTD. PROPOSED 14L TRANSMISSION LINE
--------- CALGARY POWER LTD. PROPOSED 16L/14L DOUBLE CIRCUIT TRANSMISSION LINE

DECISION 73-5 APPLICATION #6676

APPENDIX #1

ENERGY RESOURCES CONSERVATION BOARD
CALGARY, ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-5A
Application No. 6676

TRANSMISSION LINE - HIGH RIVER AREA

INTRODUCTION

The Energy Resources Conservation Board, on January 8, 1973, with Mr. Vernon Millard, Vice Chairman, and Mr. J. I. Strong, P. Eng., Board Member, sitting, heard the subject application, by Calgary Power Ltd., at a public hearing held at the offices of the Board, in Calgary, Alberta.

The Board issued its Decision 73-5, being in respect of the subject application, on March 13, 1973.

The application was for approval of two transmission lines, designated as 14L and 16L, in the High River area. The Board in Decision 73-5, approved the application, insofar as it related to the construction of 16L and to the east-west portion of 14L, as a double circuit transmission line, to be located between substation 65S and the point marked as Point A on Appendix 1, hereto attached. The Board, however, deferred its decision on the construction of the north-south portion of line 14, between the points marked as "A" and "B", on Appendix 1, in order that the Applicant and the Town of High River would have an opportunity to consider further the proposed location of the line.

VIEWS OF THE BOARD

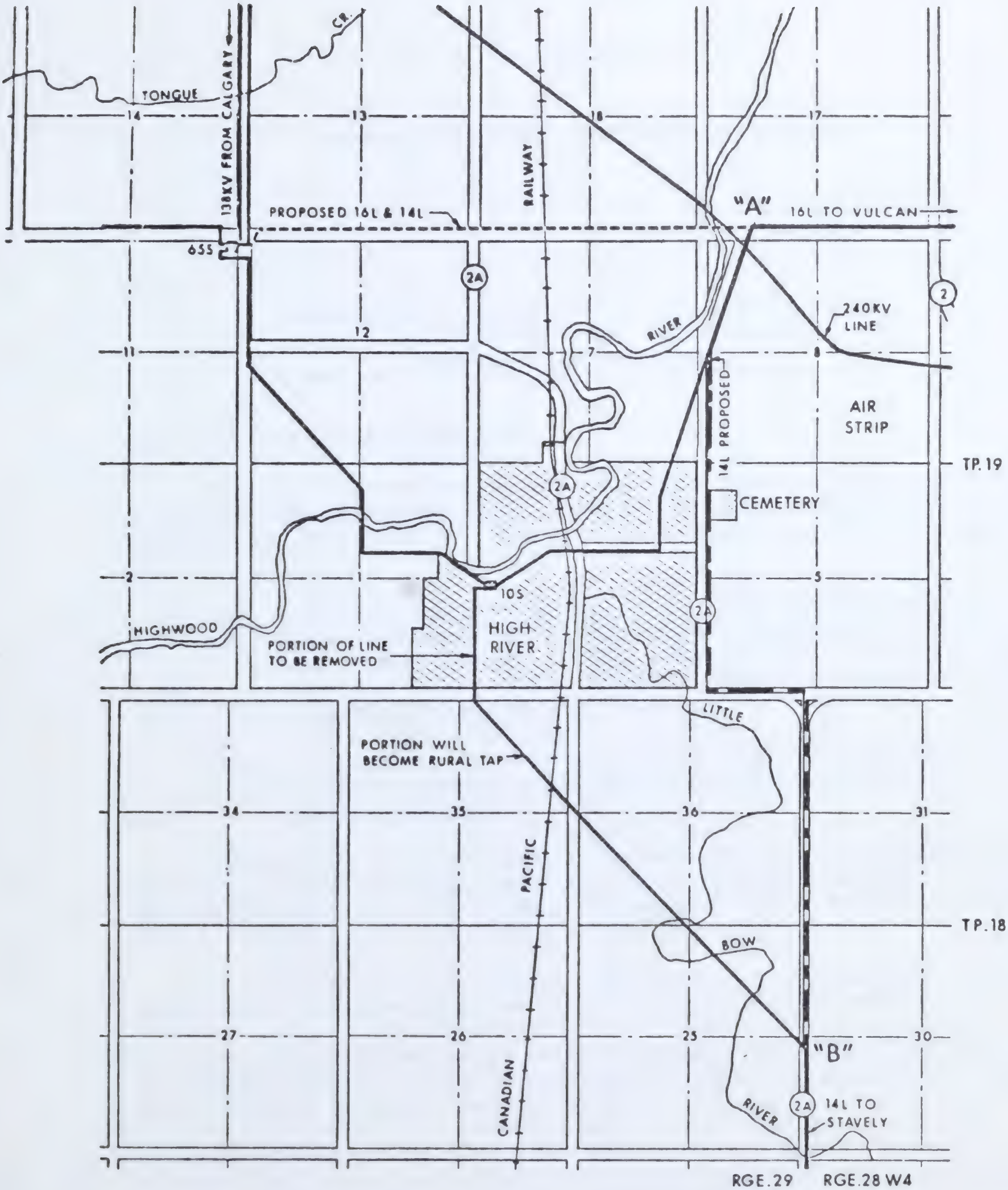
The Board noted in Decision 73-5 that the proposed route of 14 Line appeared to be the most desirable alternative, subject only to the objection of the Town of High River. By a letter dated March 27, 1973, the Board has been advised that the Town of High River has withdrawn its objections to the construction of 16 Line and 14 Line and is prepared to accept the routes proposed by the applicant.

The Board, therefore, has decided to approve the application for the construction of 14 Line, the said line to be located between the points marked as "A" and "B" on Appendix 1, hereto attached.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
April 4, 1973



PROPOSED 23KV TRANSMISSION LINE ROUTES

——— CALGARY POWER LTD. EXISTING LINES

━━━ CALGARY POWER LTD. PROPOSED 14L TRANSMISSION LINE

- - - - CALGARY POWER LTD. PROPOSED 16L/14L DOUBLE CIRCUIT TRANSMISSION LINE

DECISION 73-5 APPLICATION #6676

APPENDIX #1

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-6
Application No. 6474

CONCURRENT PRODUCTION OF OIL ACCUMULATION AND GAS CAP WITH GAS CAP CYCLING BONNIE GLEN D-3A POOL

THE APPLICATION AND HEARING

Texaco Exploration Canada Ltd., on behalf of the working interest owners in the Bonnie Glen D-3A Pool, applied, pursuant to section 38 of The Oil and Gas Conservation Act, for approval of:

(a) a scheme for concurrent production of the crude oil accumulation and its associated gas cap, with raw gas production up to 140 million cubic feet per day, removal of contained liquids, and reinjection of the remaining residue gas, and

(b) an increase in initial proved recoverable crude oil reserves from 423,000,000 stock tank barrels to 452,226,000 stock tank barrels.

Subsequent to the hearing, Texaco Exploration Canada Ltd. asked to amend its application to provide that make up of gas cap shrinkage, created by fuel consumption and liquid removal, would commence upon start-up of the cycling scheme.

The Department of Indian Affairs and Northern Development intervened for the purpose of cross-examination only.

The application was heard on October 26, 1972, by the Energy Resources Conservation Board with G. W. Govier, P. Eng., D. R. Craig, P. Eng., and V. Millard sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Texaco Exploration Canada Ltd.	J. M. Guenther R. J. Gasper, P.Eng. F. R. Thompson	Texaco

	Represented by	Abbreviation Used in Report
Department of Indian Affairs and Northern Development	E. H. King, P. Eng.	
Board Staff	G. M. Malin, P. Eng. P. M. Stanton, P. Eng. E. C. Fortems, P. Eng.	

DEFINITION OF ISSUES

The Board believes that the application requires consideration of the following matters:

(1) request to amend application,

(2) initial gas and crude oil in place,

(3) optimum crude oil and natural gas liquid recovery,

 (a) natural depletion

 (b) enhanced recovery schemes

 (c) gas cycling,

(4) prorating of vaporized oil.

1.00 REQUEST TO AMEND APPLICATION

(1) Views of Texaco

In reply to questions regarding whether the Board could recognize the 452,226,000 stock tank barrels of initial recoverable crude oil reserves claimed by Texaco as proved oil should gas cap shrinkage not be replaced, Texaco requested permission to consider the question and provide clarification subsequent to the hearing. Texaco submitted in the supplementary information supplied to the Board that it would initiate full replacement of gas cap shrinkage upon commencement of the gas cycling scheme. Should make up gas injection prove to be detrimental to field performance or not required at a later date, Texaco indicated that it would file an application with the Board requesting that make up gas injection be discontinued.

(2) Views of the Board

The Board believes that full replacement of gas cap cycling voidage will ensure that no detrimental effect on ultimate crude oil recovery will occur as a result of the gas cycling scheme. The Board therefore accepts the amendment submitted by Texaco.

2.00 INITIAL GAS AND CRUDE OIL IN PLACE

2.10 Rock Volume

(1) Views of Texaco

Texaco presented a structure map from which a gas reservoir rock volume of 719,345 acre-feet and an oil reservoir rock volume of 1,375,320 acre-feet were calculated. It indicated that the drilling of wells located in Legal Subdivision 5 and Legal Subdivision 13, both in Section 21, Township 47, Range 27, West of the 4th Meridian and Legal Subdivision 1 of Section 13, Township 47, Range 28, West of the 4th Meridian provided additional control in revising the structure map of the gross reef section, previously submitted in 1967. Texaco submitted that the gas-oil and oil-water contacts of 3965 feet subsea and 4264 feet subsea, respectively, had been established at the 1967 Annual Reserves Hearing. Under examination at the hearing respecting apparent discrepancies between the D-3 porosity tops listed on Table 8 of the study accompanying the application and those shown on the structure map provided in the same study, Texaco agreed to re-evaluate the supporting material and provide the Board with the necessary revisions.

(2) Views of the Board

The Board has considered the original data submitted by Texaco along with the supplementary information provided subsequent to the hearing. The Board notes that discrepancies still exist between the D-3 porosity tops listed in the revised tabular data and the original structure map which was not revised. For the purpose of comparison, the Board has assumed that Texaco's rock volume values are consistent with the structure map and, in doing so, has disregarded the original and revised tabular data supplied by Texaco. The Board believes that Texaco's interpretation of the crestal volume of the pool is optimistic in the light of available geological evidence. Further, the Board is of the opinion that the rock volume assigned by Texaco to that portion of the pool between 4200 feet subsea and 4264 feet subsea is optimistic in view of the limited well control in that area. The Board therefore has adopted a gas reservoir rock volume of 696,000 acre-feet and an oil reservoir rock volume of 1,365,000 acre-feet for the Bonnie Glen D-3A Pool.

2.20 Porosity

(1) Views of Texaco

Texaco volumetrically weighted the porosity values from the 3844.9 feet of core data by assuming that the reef could be subdivided into "shells" 500 feet wide measured horizontally starting from the edge of the pool. It submitted that there is statistical evidence to support the concept of increasing porosity towards the central portion of the reef very similar to that observed in a previous study of the Wizard Lake D-3A Pool. Texaco calculated a footage weighted average porosity for each shell based on all porosity data available within each of the shells. The appropriate average shell porosities were then assigned to the rock volumes of each shell in each of the 15 layers and a rock volume weighted porosity was thus determined for each layer. This volumetric weighting of the layers provided average porosities for the gas and oil reservoirs of 8.89 per cent and 9.55 per cent respectively.

(2) Views of the Board

The Board recognizes that porosity data, as plotted on maps of each of the layers, indicate some trend of increasing porosity towards the core of the reef. However, the Board is unable to accept Texaco's shell-like distribution of porosity since it is not supported by any geological theory that refers to the development of porosities in a reef in a concentric manner. The Board believes a preferable method of determining a weighted average porosity is to assume that the available porosity data in a given layer are representative of the porosity of that layer if the available core data are evenly distributed. Having regard for the limited core data available in certain areas of both the gas and oil reservoirs, the Board has adopted a gas reservoir porosity of 9.10 per cent and an oil reservoir porosity of 9.50 per cent for the pool.

2.30 Water Saturation

(1) Views of Texaco

Texaco submitted that the previously established water saturation of 6.0 per cent, which was based on oil base core data taken from the well located in Legal Subdivision 7 of Section 27, Township 47, Range 27, West of the 4th Meridian, was considered representative for the entire pool.

(2) Views of the Board

The Board agrees with Texaco that a water saturation of 6.0 per cent is representative for the entire pool. The Board therefore has revised its previous estimate of the water saturation for the gas reservoir to be consistent with that presently recognized for the oil reservoir.

2.40 Initial Oil Formation Volume Factor

(1) Views of Texaco

Texaco submitted that its revised interpretation of the initial oil formation volume factor was based on the same reservoir oil sample as used previously but was corrected to more appropriate field separator conditions of 50 pounds per square inch gauge (psig) and 40 degrees Fahrenheit (^{o}F) instead of 25 psig and 40^{o}F. It indicated that a further adjustment was made to the resulting oil formation volume factor of 1.4582 reservoir barrels per stock tank barrel at the initial datum pressure resulting in the initial formation volume factor being set at 1.4580 reservoir barrels per stock tank barrel at the initial volumetric centre of the oil accumulation.

(2) Views of the Board

The Board does not agree with Texaco that the reservoir fluid sample taken from the well located in Legal Subdivision 13 of Section 8, Township 47, Range 27, West of the 4th Meridian is representative of the initial reservoir conditions because the flash formation volume factors derived are not consistent with the corresponding gas-oil ratios. Rather the Board believes that the reservoir fluid sample taken from the well located in Legal Subdivision 14 of Section 17, Township 47, Range 27, West of the 4th Meridian is more representative. Also, the Board believes that 50^{o}F is more representative of the average temperature of separation. The Board agrees with Texaco that the initial oil formation volume factor calculated at the initial volumetric centre of the oil accumulation is more representative than that determined at the datum depth. However, the Board notes that the effect of this adjustment on this factor is negligible. The Board has assigned an initial oil formation volume factor of 1.469 reservoir barrels per stock tank barrel to the pool.

2.50 Summary of Initial Gas and Crude Oil in Place

(1) Views of Texaco

Based on the reservoir parameters discussed above and fluid properties adopted. Texaco calculated an initial gas cap gas in place of [illegible] billion cubic feet (Bcf) and an initial crude oil in place of [illegible] stock tank barrels (STB). The reservoir factors used by Texaco are shown in Table [illegible].

(b) Views of the Board

The Board has assigned an initial gas cap gas in place of [illegible] Bcf and an initial crude oil in place of [illegible] million STB based on the reservoir parameters previously assigned and those adopted herein. These reservoir factors are shown in Table [illegible].

1.30 OPTIMUM HYDROCARBON RECOVERY

1.31 Natural Depletion

(a) Views of Texaco

Texaco submitted that the residual oil saturations in the gas and water flushed parts of the pool, previously presented at the 1967 Annual Reserves Hearing, were established from tests conducted by Texaco Inc. Research and Technical Department on large diameter core samples. Results of these tests indicated a residual oil saturation in the gas flushed part of [illegible] per cent pore volume and a range in residual oil saturation in the water flushed part from 35.4 per cent pore volume at zero gas saturation to 32.9 per cent pore volume at a critical gas saturation of 10.0 per cent pore volume. Texaco contended that these parameters are substantiated by the excellent comparison between calculated and observed gas-oil and oil-water interfaces derived from its one-dimensional model.

Texaco submitted that the interference model developed and used for Wizard Lake miscible flood predictions, using an analytical approach based on unsteady state methods and incorporating all pools in the Acheson to Homeglen Rimbey reef chain, had provided an excellent historical pressure and water influx match for the Bonnie Glen D-3A Pool. The results of this match were incorporated into a one-dimensional simulator to calculate the gas-oil and oil-water interface movement for Bonnie Glen.

Texaco presented three case studies which had been investigated to determine the best match between observed and calculated interfaces. The three case studies included a critical gas saturation ranging from 4.7 per cent pore volume, the value determined for the Wizard Lake D-3A Pool, to 10.0 per cent pore volume; layered porosity with an average oil reservoir porosity varying from 9.44 per cent to 9.55 per cent; and both previously adopted and revised PVT data. In addition, Texaco assumed a residual oil saturation in the gas flushed part of the pool of 24.5 per cent pore volume, with a declining residual oil saturation in the water flushed part of from 35.4 per cent pore volume at zero gas saturation to 32.9 per cent pore volume at a 10.0 per cent pore volume gas saturation. In all three cases studies, current mapping of the Bonnie Glen reef structure and the respective initial gas and crude oil in place values were used. Texaco indicated that satisfactory agreement between calculated and observed gas-oil and oil-water interface movement could only be obtained using layered porosity with an average oil reservoir porosity of 9.55 per cent, revised PVT data and a critical gas saturation of 10.0 per cent pore volume. Texaco therefore contended that these results substantiate the revisions to the PVT data, critical gas saturation and layered porosity. At the 1973 Annual Reserves Hearing, Texaco stated that it regarded the gas saturation of 10.0 per cent pore volume to be a combination of a critical (immobile) gas saturation plus gas in transit migrating toward the gas cap.

Texaco submitted that its prediction of recovery by natural depletion was obtained from its one-dimensional interface movement simulator incorporating revised reservoir and PVT parameters and pressure-influx data derived from predicted production-injection schedules for each pool in the Golden Trend. Texaco indicated that the oil and gas balances which were maintained in the model signified a close control on material balance and justified using the model for Bonnie Glen recovery predictions. The applicant also submitted the results of both a productive capacity study, based on coning considerations for those wells having both gas-oil and oil-water interfaces and those having only an oil-water interface, and a coning correlation assuming a completely homogeneous reservoir. Assuming a five-foot terminal sandwich loss as indicated from the coning correlation and a water coning test, Texaco submitted that the initial proved recoverable crude oil reserves of the Bonnie Glen D-3A Pool be established at 452,226,000 stock tank barrels or 68.8 per cent of the 657,138,000 stock tank barrels in place.

Texaco further submitted that subsequent to depletion of the oil reservoir, estimated to occur by 1996, blowdown of the gas cap would commence. It assumed that a linear pressure decline with no water influx would occur throughout the blowdown period with a terminal reservoir pressure of 250 psig. Texaco predicted the total liquid recovery to be 34,934,000 barrels during blowdown of the gas cap after natural depletion as shown in Table 3.01.

(5) Views of the Board

The Board has reviewed the test data obtained from gas and water displacement tests conducted on four Bonnie Glen D-3 core samples in 1956. The Board believes that the test data indicate that gas flooding and water flooding result in similar displacement efficiencies of either displacing fluid at equal displacement volumes. In adopting this view, the Board is of the opinion that Texaco's interpretation of the level of residual oil saturation in the water flushed part of the pool is questionable in that:

(i) the water flood test data are only available for a displacement of two pore volumes, making the extrapolation to an end point rather uncertain;

(ii) the results of the four water flood tests, conducted by the same laboratory using the same handling techniques, varied by more than 10 saturation percentage points at a level of about 30 to 40 per cent pore volume, which does not allow the Board to place full reliance in these data; and

(iii) residual saturations after water flood in the range of 25 to 30 per cent pore volume are indicated for other D-3 pools similar to Bonnie Glen.

The Board has studied the question of residual oil saturations as indicated by production performance with the aid of a one-dimensional vertical model. The model used 26 horizontal layers to describe the gas, oil and water bearing parts of the pool. The layer thicknesses were varied so that oil saturations in the gas and water flushed parts of the pool could effectively be used to describe the movement of the gas-oil and oil-water interfaces. The reservoir rock properties assigned to each layer were determined by interpolation of core analysis data. Several simulations were run to determine the effect of different reservoir parameters on the calculated movement of the gas-oil and oil-water interfaces. The simulations included a residual oil saturation in the gas flushed part of the pool varying from 15 to 25 per cent pore volume, a residual oil saturation in the water flushed part varying from 15 to 33 per cent pore volume, a critical gas saturation varying from 5 to 10 per cent pore volume and layered porosity.

The simulations verified Texaco's conclusion that, within reasonable limits, the critical gas saturation was the most significant factor affecting the movement of the calculated gas-oil interface while the residual oil saturation in the water flushed part of the pool was the major influence on the movement of the calculated oil-water interface. The simulations further illustrated that the best match of the history of the movement of the gas-oil and oil-water interfaces could be achieved using a higher residual oil saturation in the water flushed part of the pool than in the gas flushed part. However, there is considerable uncertainty associated with the pore volume assigned in the water flushed part of the pool, so that a reasonable match of the movement of the oil-water interface might be obtained by a reasonable downward adjustment in pore volume of the water flushed part and a corresponding reduction in residual oil saturation under water displacement.

The Board believes that insufficient reliable evidence is available to warrant altering its opinion of the level of residual oil saturation in the water flushed part of the pool based on laboratory tests. The Board has chosen to assign a residual oil saturation of 25 per cent pore volume for both displacement by gas and water to the Bonnie Glen D-3A Pool. The Board further believes that a critical gas saturation of 5 per cent pore volume is realistic for a pool such as Bonnie Glen. However, having determined that the most consistent history match of the movement of the gas-oil interface could be obtained using an oil reservoir gas saturation of 10 per cent pore volume, the Board has decided to accept this value for the pool. The Board assumes, as did Texaco, that this total gas saturation is a combination of immobile and mobile gas in the oil bearing part of the pool at this time and that it also accounts for several unknown variables and errors inherent in the calculations.

The Board has considered the question of recovery by natural depletion from the Bonnie Glen D-3A Pool in conjunction with the 1973 Annual Reserves Hearing. Decision 73-4 may be referred to for a discussion of this matter. The Board has adopted initial proved recoverable crude oil reserves under natural depletion of 444 million stock tank barrels or 69.0 per cent of the 643 million stock tank barrels in place for the Bonnie Glen D-3A Pool.

The Board's estimate of the total liquid recovery during blowdown of the gas cap after natural depletion differs little from that submitted by Texaco as shown in Table 3.01.

[illegible] Enhanced Recovery Schemes

(1) Views of Texaco

Texaco submitted that several different enhanced recovery schemes were investigated to determine a technically feasible and economic project for the Bonnie Glen D-3A Pool. Those schemes investigated were:

(a) pressure depletion with a constant oil-water interface,

(b) pressure maintenance by water injection,

(c) pressure maintenance by water and gas injection with a constant oil-water interface, and

(d) solvent flooding.

Texaco predicted that continued natural depletion of the oil reservoir with a stabilized oil-water interface would require a cumulative injection of 84 million barrels of water and 84 billion standard cubic feet of gas. However, Texaco considered this scheme to be uneconomic as the incremental crude oil recovery would be only 3,361,000 stock tank barrels over continued natural depletion.

The applicant predicted that the injection requirements to maintain the pool pressure at its present level would be 564 million barrels of water at rates up to 143,000 barrels of water per day. Since Texaco submitted that flushing by water is less efficient than by gas in the subject pool, it calculated that the crude oil recovery would be 426,930,000 stock tank barrels or a net loss of 25,296,000 stock tank barrels over continued natural depletion.

Texaco indicated that the injection requirements to maintain the pool pressure at its present level and stabilize the oil-water interface would be 307 billion standard cubic feet of gas and 258 million barrels of water at rates up to 88.6 million cubic feet and 52,500 barrels per day. The applicant considered that the additional crude oil recovery of 6,913,000 stock tank barrels was not economically justifiable in view of the cost of the large gas volumes required for injection.

Texaco submitted that a preliminary economic analysis of implementing a solvent flood scheme in Bonnie Glen had been presented to the Board in October 1971. The study concluded that, although a solvent flood scheme was technically feasible, the large injection volumes of solvent and gas required made the project uneconomic.

(2) Views of the Board

On the basis of Texaco's residual oil saturations, the Board would agree with Texaco's conclusions respecting each of the enhanced recovery schemes discussed above. However, with the adoption by the Board of residual oil saturations by gas and water displacement of 25 per cent pore volume, the Board's estimate of the incremental oil recovery for each of the schemes considered is not the same as that submitted by Texaco.

The Board estimates that continued natural depletion of the oil reservoir with a stabilized oil-water interface would result in a slight loss in crude oil recovery over continued natural depletion.

The Board is of the opinion that the additional crude oil recovery resulting from pressure maintenance by water and gas injection with a constant oil-water interface would not be economically justifiable in view of the cost of the large gas volumes required for injection.

The Board is satisfied that, although a solvent flood scheme is technically feasible, the cost of the large injection volumes of solvent and gas required would make the scheme uneconomic.

From its analysis, the Board therefore concludes that pressure maintenance by water injection is the only enhanced recovery scheme in which the incremental crude oil recovery might be justified economically. Based on assigned residual oil saturations of 25 per cent pore volume, the Board predicts that the incremental crude oil recovery attributable to such a scheme would be approximately 13 million stock tank barrels. Injection requirements to achieve this would be at least 650 million barrels of water at rates up to 150,000 barrels of water per day. However, the Board has estimated that the loss in gas plant liquid recovery attributable to vaporization and shrinkage of residual oil in a reduced gas flushed part of the pool and a reduction in the volume of liquid recovered from solution gas released from the oil part would be approximately comparable to the estimated incremental crude oil recovery attributable to pressure maintenance by water injection. The Board therefore concludes that, on the basis of total liquid recovery, pressure maintenance by water injection would not be justified.

3.36 GAS CYCLING

Simultaneous production of a gas cap and its associated oil column is usually detrimental to crude oil recovery, and sound policy requires that gas cap production ordinarily be deferred until depletion of the oil column. However, this policy does not preclude the cycling of gas cap gas for liquid recovery while depleting the oil column where improved conservation will result.

(i) Views of Texaco

Texaco employed black oil and multi-component compositional models to simulate a gas cycling scheme at a rate of 400 million cubic feet per day. The process of gas cycling would consist of gas production from both the original gas cap and the gas flushed part of the original oil column. The produced gas would then be processed for liquid removal and the remaining residue gas would be reinjected into both the original gas cap and the gas flushed part of the pool. Furthermore, additional gas would be injected to replace gas cap voidage caused by the removal of liquids and by fuel consumption. Texaco stated that as a result of the cycling scheme liquid recovery would be increased through both vaporization of retrograde liquids in the gas cap and vaporization of some of the residual oil in the gas flushed part of the original oil column. The gas flushed part referred to is continually enlarging due to depletion of the oil column and expansion of the original gas cap into the depleted part of the pool. The gas in place in the gas cap is also continually increased by solution gas released from crude oil by pressure decline, which when present in the oil reservoir in excess of the formation's critical gas saturation, migrates upward to the gas cap.

To examine the cycling performance, Texaco employed a two-dimensional and three-dimensional multi-component simulator ("XCOMP"). Since the most important part of compositional simulation lies in the preparation of the correct phase behaviour data, equilibrium ("K") values were empirically correlated with data determined by laboratory experiments performed on Bonnie Glen hydrocarbon samples. Texaco stated that it satisfactorily matched several laboratory studies including a differential liberation of an oil sample, a step-wise equilibrium depletion test and the resulting retrograde condensation of a gas cap sample, and a vaporization study, all of which confirmed a satisfactory correlation of "K" values as a function of both pressure and composition.

Using the compositional model, Texaco predicted a recovery of 111.745 million stock tank barrels of gas plant liquids during the cycling scheme with an additional recovery of 11.286 million stock tank barrels during blowdown of the gas cap. This total liquid recovery of 125.031 million stock tank barrels gave an apparent incremental recovery of 90.097 million stock tank barrels when comparing cycling and blowdown with continued natural depletion. The apparent incremental recovery reduces to 64.906 million stock tank barrels after allowing for the differences in ethane plus components in the sales gas between the cycling and natural depletion cases. The individual component recoveries are presented in Table 3.01.

Texaco maintained that initial liquid production from the gas plant would not be identifiable as to source, but by an independent calculation, the applicant estimated that approximately 50 per cent of the liquid recovery during cycling or some 57 million stock tank barrels would be attributable to products initially contained in the original oil column.

Texaco compared the amount of vaporization predicted by the compositional models with studies performed by the Bureau of Mines, United States Department of the Interior(1), and concluded that liquid volumes vaporized appear to be realistic.

The compositional model study was conducted for a cycling rate of 140 million cubic feet per day and results were estimated for cycling rates of 50, 100 and 200 million cubic feet per day. The interpolated rates of 50 and 100 were considered by Texaco to be realistic but the extrapolated recovery for the 200 million cubic feet per day rate was judged to be questionable as the liquid content fell outside the range of investigation. Notwithstanding these uncertainties, Texaco estimated an additional 15.864 million barrels of liquid hydrocarbons could possibly be vaporized at higher cycling rates. However, Texaco indicated that the higher recoveries attainable through higher cycling rates were influenced by the assumption that cycling for all rates would terminate in 1996. Since blowdown would continue for an estimated 22 years past 1996, it was considered highly probable that cycling would continue past 1996 in conjunction with blowdown. Texaco maintained that comparable recoveries could be achieved by varying the length of cycling time. Considering the above and the fact that there is a degree of risk in assuming the large amount of residual oil from the gas swept part that would be vaporized, Texaco submitted that the 140 million cubic feet per day cycling rate is practical and justified.

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(1) Cook, A.B., Walker, C.J., and Spencer, G.B.: "Realistic K Values of $C_{7}+$ Hydrocarbons for Calculating Oil Vaporization During Gas Cycling at High Pressures", Paper SPE 2276, (Sept. 1968)

Texaco examined the economics of the cycling scheme using a 10 per cent present worth operating profit after taxes and an initial gas price of 16 cents per thousand standard cubic feet (16¢/Mscf) with an escalation in gas price of 0.4 cents per year. At the Board's request for economic comparisons at elevated initial gas prices, two additional evaluations were submitted using initial gas prices of 26 cents and 36 cents. These gas prices were assumed to escalate one cent per year after 1973. Texaco prepared the attached Figure 3.01 to indicate the effect of higher costs of make up gas in the economics of the proposed cycling scheme. Referring to Figure 3.01, optimum economic cycling rates occurred at approximately 140, 125 and 114 million cubic feet per day for the three schedules of 16, 26 and 36 cents respectively. Texaco indicated that cycling at rates over 140, although less attractive economically, could still be acceptable. However, it was submitted that other factors must be considered as previously discussed.

(2) Views of the Board

The Board requested that Texaco re-examine the economics of the proposed cycling scheme by utilizing higher gas price schedules when evaluating the cost of the make up gas required. It was the Board's intention to determine if the proposed scheme would be altered by Texaco should increased gas prices prevail over those assumed in the original analysis. The Board did not examine the economics in any detail, but it accepts the analysis of Texaco, shown in Figure 3.01, that a less favourable profit position would result if higher gas price schedules come into effect. Texaco did not amend its proposed cycling scheme as a result of the aforementioned analysis.

The Board concurs with the applicant that cycling will increase liquid hydrocarbon recovery by vaporizing retrograde liquids and a portion of the residual oil. However, the Board does not accept the incremental recovery attributed to the scheme of 64.906 million barrels as presented by Texaco. In particular, the Board believes that the incremental recovery attributable to products originating in the oil reservoir may be somewhat optimistic. This conclusion was reached after a careful examination of the proposed incremental recoveries, the methods used in modelling the compositional behaviour, and a study of pertinent material relating to vaporization effects during dry gas cycling of gas-condensate-oil systems.

The Board appreciates the complexities experienced by Texaco in modelling such a scheme and notes Texaco's statement that the procedures used at the time were the best available and that recent developments in compositional modelling could possibly lead to better predictions. However, the questionable areas need some comment, even though the comments generally are of a qualitative nature. Basically, the Board is concerned with the following matters:

(a) the number of pseudo-components necessary to define adequately the heptane plus fraction (C_7+),

(b) the adequacy of the laboratory vaporization study to represent the reservoir behaviour,

(c) the shortage in oil recovery of 20 million stock tank barrels obtained when using the compositional model as compared to the predicted oil production, and

(d) the interpretation of the vaporization study conducted by the Bureau of Mines, United States Department of the Interior.

Generally, in the simulation of gas cycling a modelling problem is created by considering the heptane plus fraction as a single lumped parameter. Assigning one equilibrium (K) value to this lumped component is an oversimplification and does not recognize that the volatility of the C_7+ fraction of reservoir oil decreases rapidly when dry gas is cycled past it. Calculations using C_7+ as a lumped parameter usually indicate greater vaporization of oil when compared to calculations which treat the C_7+ as composed of some 15 pseudo-components. Texaco subdivided the C_7+ fraction into four pseudo-components to alleviate this problem. The Board appreciates that the applicant made a practical approach but believes that the use of this limited subdivision would result in vaporization predictions which would be somewhat higher than would be physically realized. The Board is unable to judge the extent of the inflation.

The laboratory vaporizatian study employed by Texaco was designed to investigate vaporization effects on residual oil throughout the pressure range of 2144 to 2035 pounds per square inch absolute (psia). The study was performed by successively contacting the reservoir fluid with approximately equal volumes of injection gas and by allowing this system to attain equilibrium at the various pressure levels. Each equilibrium gas product was then analysed and measured and the volume of oil remaining was determined at each pressure step. The Board believes that for gas cycling simulation, when K values are to be matched to laboratory experiments such as the aforementioned, the study should cover the range of concentrations and pressures expected during the cycling process. For example, in this case the study should examine vaporization behaviour throughout the pressure range from approximately 2000 to 1400 psia. Considering the limited pressure range examined by Texaco in its laboratory study, the Board is of the opinion that the K values matched to this vaporization experiment may not adequately define the compositional behaviour of the cycling scheme. As a result, additional errors in predicted volumes of vaporized oil could be expected.

Texaco indicated that the cumulative oil production estimated by its compositional simulator (NCOMP) was approximately 433 million stock tank barrels or some 20 million stock tank barrels less than the predicted crude oil recovery of 452 million stock tank barrels. Texaco submitted several explanations for the discrepancy, one of which was that inaccuracies in K values used for the field separator conditions in the compositional model resulted in the prediction of an excessive amount of liquid being vaporized in the separator gas. The Board considered that one possible explanation for the oil shortage was that the compositional model was predicting excessive vaporization of the residual oil in the reservoir. The applicant conceded that this possibility existed, but it was not the explanation it favoured.

The Board does not agree with the applicant that the volumes of oil vaporized appear to be realistic when compared with studies performed by the U. S. Bureau of Mines (USBM). Texaco maintained that the USBM laboratory tests closely approximate that of cycling in Bonnie Glen. However the USBM study was conducted at a constant pressure of 2600 psia and indicated approximately 35 per cent of the residual oil could be vaporized after injection of two pore volumes of dry gas. The study also indicated that vaporization is a function of pressure with the volume of oil vaporized decreasing with reduced pressure levels for a given dry gas injection volume. Examination of the proposed operating scheme indicates an initial pressure at commencement of cycling of approximately 1900 psi with a reduction in pressure to approximately 1400 psi after one pore volume of dry gas has been injected. The problem is further complicated by the fact that the USBM study incorporates a fixed gross pore volume while in the proposed Bonnie Glen scheme, the gross pore volume exposed to injected gas is continually increasing as the oil reservoir is depleted. Therefore it is complex to predict oil volumes vaporized for a given number of pore volumes injected if the prediction is to be based on the USBM study. For example when one pore volume of gas has been injected, there would be a gradation in effective pore volumes cycled throughout the residual oil part of the pool with the upper areas of the part benefiting from more than one pore volume of dry gas, to the lower areas where the dry gas contact would be minimal.

Using Texaco's estimate of some 57 million stock tank barrels of vaporized oil recovery and a residual oil volume before vaporization of some 126 million stock tank barrels as indicated in Table 4 of Exhibit I, it appears that approximately 45 per cent of the residual oil is expected to be recovered. Considering the aforementioned problems and variables, the Board believes that to expect vaporization of 45 per cent of the residual oil in this case is unrealistic. Based on its own interpretation of the USBM study the Board would not expect that more than 20 per cent of the residual oil would be vaporized.

The Board noted a further discrepancy in Texaco's study. Calculations were performed to estimate the volume of vaporized oil based on residual oil saturations in the gas flushed part of the pool. By multiplying the residual oil saturation after vaporization (Table 55 to Exhibit I) by the pore volume for each layer and by summing the products for all layers in the original oil column, a residual oil volume of some 132 million reservoir barrels was estimated. This figure was compared with the residual oil volume of some 154 million reservoir barrels (Table 47 to Exhibit I) remaining in the gas flushed part of the pool when vaporization was not considered. The difference of some 22 million reservoir barrels or approximately 17.5 million stock tank barrels should be the recovery volume attributable to vaporized oil. In addition, the Board believes that a portion of the products attributed by Texaco to vaporization are in fact a result of shrinkage of the residual oil during pressure depletion. The Board estimated this volume by comparing the previously discussed number of 154 million reservoir barrels to an estimated residual volume before oil shrinkage of some 165 million reservoir barrels (product of Texaco's estimate of residual oil saturation in the gas flushed part of the pool of 24.5 per cent and the appropriate pore volume). The difference of some 8 million stock tank barrels (11 million reservoir barrels) is the volume attributed to shrinkage of the residual oil. The total volume of some 25.5 (17.5 + 8) million stock tank barrels attributable to products originating in the residual oil of the gas swept part is in contrast to the previously discussed estimate by Texaco of 57 million stock tank barrels.

For simplification, further reference to vaporized oil when used by the Board will include that volume resulting from shrinkage of the residual oil in the gas flushed part of the pool.

Having regard for Texaco's own reservations, the previously discussed differences and considering that methods of determining oil vaporization are relatively new, the Board believes that it should place a conservative estimate on that volume of recoverable liquids attributable to vaporized residual oil. Therefore the Board adopts an estimate of 20 million stock tank barrels of gas plant liquid recovery attributable to vaporized oil. Total gas plant liquid recovery for the proposed scheme is estimated to be in the range of 90 million stock tank barrels when considering an ethane plus product. Of this volume, 65 million stock tank barrels are estimated to result from the cycling scheme while the remaining 25 million stock tank barrels mainly result from the increased processing of the raw gas to obtain an ethane plus product. The actual incremental recovery, over natural depletion-blowdown, on a component basis is estimated to be 30 million stock tank barrels. These estimates are presented in Table 3.01.

The Board is satisfied with the cycling rate chosen and agrees with the applicant that, within a limited range, comparable recoveries are possible by variations in the cycling rate-cycling time interrelationship. Furthermore, authorization of blowdown, proposed for 1996, would be made following an assessment of the results of operations after several years. This does not preclude the possibility of continued partial cycling during blowdown.

Although the Board does not agree with Texaco on the volume of liquids attributable to vaporized oil, the Board is generally satisfied with the proposed cycling scheme, amended to ensure full gas cap voidage replacement, as there will be no detrimental effect on crude oil recovery over the life of the scheme and the overall operation of the pool will provide optimum economic recovery of oil and gas.

4.00 PRORATING OF VAPORIZED OIL

(i) Views of Texaco

Texaco requested that the production of additional oil recovery as natural gas liquids through vaporization be excluded from proration. In support of this request, the applicant indicated that the initial production would not be definable as to source and, in any event, the oil reservoir would only substantially contribute to the production of liquids resulting from the cycling scheme after one pore volume of gas cap cycling. Texaco stated that all indications were that proration would not be in effect at the end of this 8.9 year period.

(2) Views of the Board

The Board does not consider it necessary, at this time, to address itself to the question of whether, under The Oil and Gas Conservation Act, the hydrocarbons recovered by the vaporization of crude oil in the reservoir would fall within the definition of crude oil. It appears that the production of vaporized oil from the gas invaded oil reservoir will not occur for at least five years. The Board agrees with Texaco that indications are that the proration plan, in its present form, will not be in effect at that time. The Board therefore approves Texaco's request to exclude from proration the production of additional oil recovered as natural gas liquids through vaporization. This approval is subject to periodic review in the light of the crude oil marketing situation and information obtained from the monitoring of gas plant products.

OTHER MATTERS

The Board believes that two matters which require consideration but do not warrant being dealt with as major issues are the effect on Bonnie Glen of possible future operational changes to other pools in the Golden Trend and the monitoring of both the liquid composition and content of the reservoir fluid produced from the gas wells in the Bonnie Glen D-3A Pool.

As outlined in Decision 73-4, the Board considers that the operator of a pool has a responsibility to control the operations of his pool so that significant damaging effects on the neighbouring pools do not occur. Therefore, the Board may, from time to time, require a review of the operations and behaviour of the pools in the Golden Trend including Bonnie Glen, and may require changes in the method of operation in the interest of better conservation.

The Board considers the monitoring of both the liquid composition and content of gas well production to be necessary to allow review of the progress of the scheme and to ensure that no proratable crude oil produced by coning is being inadvertently produced from the gas wells. Details of the monitoring program will be discussed with Texaco and subsequently contained in the approval of the scheme.

SUMMARY OF THE BOARD'S FINDINGS

(1) Gas cap voidage replacement, as requested by Texaco, will ensure that no detrimental effect on ultimate crude oil recovery will occur as a result of the gas cycling scheme.

(2) The assigned initial gas cap gas in place is [illegible] billion cubic feet and the initial crude oil in place [illegible] million stock tank barrels. The initial proved recoverable crude oil reserves are 444 million stock tank barrels.

(3) There is insufficient evidence to warrant assigning different residual oil saturations to the water flushed part of the pool and the gas flushed part at this time. A residual oil saturation of 25 per cent pore volume is adopted for displacement by both gas and by water.

(4) The use of a pseudo-critical gas saturation of 10.0 per cent pore volume is necessary to obtain a suitable history match of the movement of the calculated and observed gas-oil interfaces. The true critical gas saturation is probably somewhat less than 10.0 per cent pore volume.

(5) Natural depletion of the oil column with gas cap cycling at full gas cap voidage replacement appears to be the optimum production scheme for the pool.

(6) The amount of liquid recovery attributable to vaporized crude oil as estimated by Texaco is considered to be optimistic. An estimate of 20 million stock tank barrels is adopted for the recovery by shrinkage and vaporization of residual crude oil in the gas flushed part of the pool.

(7) Texaco's proposed cycling scheme is satisfactory to the Board.

(8) The product resulting from the partial recovery of residual crude oil by vaporization and shrinkage is not subject to proration at this time.

DECISION

The Board grants approval of Texaco's scheme, as amended, of production of crude oil and gas from the Bonnie Glen D-3A Pool as follows:

1. The oil accumulation and its associated gas cap may be concurrently produced in accordance with Board Approval No. 1863 being issued concurrently with this decision.

2. Gas cycling of the gas cap with full gas cap voidage replacement is approved in accordance with Board Approval No. 1863.

3. The initial proved recoverable crude oil reserves adopted for the pool in accordance with the approved scheme are as shown in Table 2.01 under the column "Board".

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
March 23, 1973

ENERGY RESOURCES CONSERVATION BOARD

Table 2.01 to Decision 73-6

BONNIE GLEN D-3A POOL

Comparison of Oil Column and Gas Cap Reservoir Parameters and Reserves from Texaco Application and as Adopted by the Board

Parameter	Texaco	Board
A. Oil Column		
Oil Column Rock Volume (Acre-feet)	1,375,320	1,365,000
Area (Acres)	8,578*	7,500*
Thickness (Feet)	(160.3)	(181.9)
Porosity	0.0955	0.095
Water Saturation	0.06	0.06
Shrinkage	0.6859	0.68
Oil in Place (Million STB)	657.138	643
Primary Recovery Factor	0.688	0.69
Primary Recovery (Million STB)	452.226	444
Residual Oil Saturation		
(a) Gas flushed part of the pool (%)	24.9	25
(b) Water flushed part of the pool (%)	35.4 - 32.9**	25
B. Gas Cap		
Gas Cap Rock Volume (Acre-feet)	719,345	696,000
Porosity	0.0889	0.091
Water Saturation	0.06	0.06
Gas in Place		
Gas Cap (Bcf)	444.9	445
Solution Gas (Bcf)	-	512
Marketable Gas (Bcf)	403.6***	
Gas Cap (Bcf)	-	310
Solution Gas (Bcf)	-	280

* Area at O/W contact

** Reflects gas saturation variation from 0 per cent to critical gas saturation of 10 per cent

*** This volume includes gas cap gas plus gas released from the oil column for contribution to the gas cap. It does not include solution gas recovery from the oil wells.

ENERGY RESOURCES CONSERVATION BOARD

Table 3.01 to Decision 73-6

BONNIE GLEN D-3A POOL

Comparison of Gas Plant Liquid Recoveries
from Texaco Submission and as
Estimated by the Board

A. ACTUAL LIQUID RECOVERY

Component	Natural Depletion-Blowdown		Gas Cycling Project					
	Texaco	Board	Cycling	Blowdown Texaco	Increment	Cycling	Blowdown Board***	Increment
Sales Gas (Bcf)	447.3	432	-	403.6	-43.7			
Ethane (MMBbls)	-	-	34.326	3.397	37.723			
Propane (MMBbls)	14.309	14.5	30.145	3.437	19.273			
Butane (MMBbls)	8.286	8.7	18.989	1.375	12.078			
Pentanes Plus (MMBbls)	12.339	12.7	30.285	3.077	21.023			
Total Liquids (MMBbls)	34.934	35.9	113.745	11.286	90.097	79	11	55

B. ** FLUID RECOVERY

Component	Natural Depletion-Blowdown Texaco	Gas Cycling Project					
		Cycling	Blowdown Texaco	Increment	Cycling	Blowdown Board***	Increment
C_2 (MMBbls)	33.463	34.326	12.189	13.052			
C_3 (MMBbls)	15.899	30.145	4.437	18.683			
C_4 (MMBbls)	8.370	18.989	1.524	12.143			
C_{5+} (MMBbls)	12.339	30.285	3.082	21.028			
Total Liquids	70.071	113.745	21.232	64.906	79	21	30

* Gas recovered from gas cap and from solution gas released to the gas cap

** Considering equivalent barrels of each component contained in the sales gas

*** Estimates of total liquid recovery only

Note: Total liquid recovery under the proposed scheme is:

Texaco (113.745 + 11.286)	125.031	MMSTB
Board (79 + 11)	90	MMSTB (approx.)

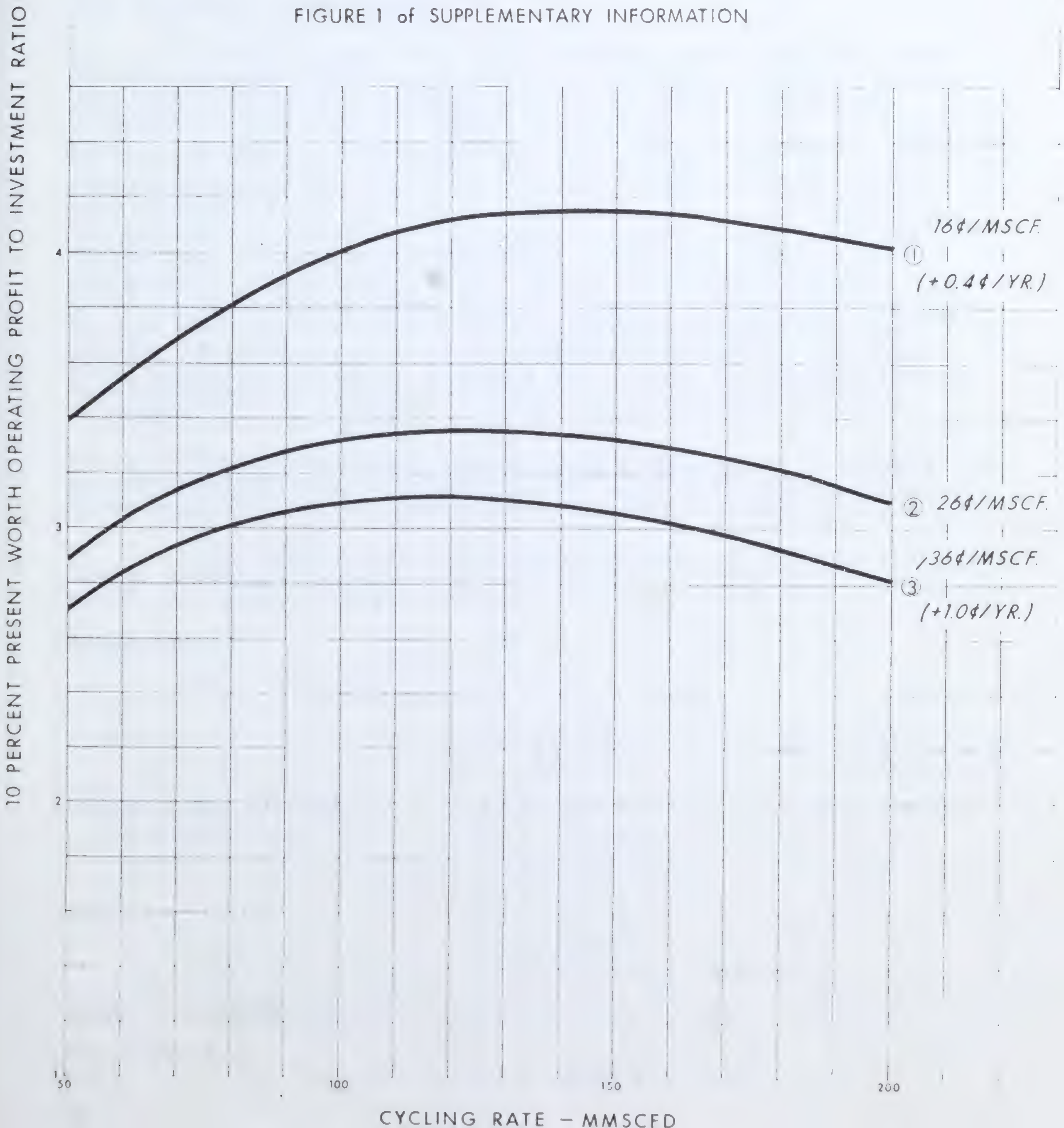
Increment is difference between Gas Cycling Scheme and Natural Depletion - Blowdown Scheme

FIGURE 3.01 TO DECISION 73-6

CYCLING PLANT ECONOMICS AFTER INCOME TAX FOR VARIOUS CYCLING RATES AND GAS PRICE SCHEDULES

APPLICATION No. 6474

FIGURE 1 of SUPPLEMENTARY INFORMATION



ENERGY RESOURCES CONSERVATION BOARD

Decision 73 - 7
Application No. 6405

EXEMPTION FROM SULPHUR RECOVERY GUIDELINES KAYBOB SOUTH BEAVERHILL LAKE GAS UNITS 1 AND 2

THE APPLICATION AND HEARING

Hudson's Bay Oil and Gas Company Limited applied (under The Oil and Gas Conservation Act) for exemption from the sulphur recovery efficiency guidelines set out in Board Informational Letter No. 71-29, for the Kaybob South Beaverhill Lake Gas Units 1 and 2 processing plants located in Township 62, Range 20, West of the 5th Meridian. Approval No. 1415 and Approval No. 1730 currently permit the plants to process a combined maximum equivalent sulphur inlet volume of 2,180 long tons per day and require the recovery in the form of elemental sulphur of not less than 96 per cent of the sulphur contained in the gas delivered to the plant. Informational Letter No. IL 71-29 specifies that a plant, with a sulphur inlet rate of between 1000 to 4000 long tons per day of sulphur and processing favourable quality acid gas, recover 98 to 99 per cent of the sulphur delivered to the plant after December 31, 1974. Hudson's Bay Oil and Gas Company Limited requests that the sulphur recovery efficiency required remain unchanged at 96 per cent.

Chevron Standard Limited made a submission in support of the application by Hudson's Bay Oil and Gas Company Limited. There were no other interventions respecting the application.

The application was heard on October 10, 1972 by the Energy Resources Conservation Board with G. W. Govier, P. Eng., and D. R. Craig, P. Eng., sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Hudson's Bay Oil and Gas Company Limited	B. F. Sim M. I. Danielson P. C. Morgan G. A. McInnis M. B. Field M. D. Phillips L. H. Hammond H. W. Becker, P. Eng.	Hudson's Bay
Chevron Standard Limited	E. E. Cudby, P. Eng.	Chevron
Board Staff	L. A. Mazurek, P. Eng. R. B. Dunbar, P. Eng.	

SUBMISSION OF HUDSON'S BAY

Hudson's Bay stated that it should be granted relief from the requirements of the minimum sulphur recovery efficiency guidelines since the production mechanism differs from the normal depletion of a reservoir by blow down. In the Kaybob South operation, liquids and sulphur are removed from the raw gas and 52 per cent of the raw gas volume is re-injected as dry sweet gas to maintain the reservoir pressure and increase the liquid hydrocarbon recovery.

Hudson's Bay stated that its production forecasts for the reservoir indicate that significant breakthrough of residue gas will occur in 1976 which will result in a reduction of the sulphur content in the inlet gas to the plants. Termination of the cycling phase is predicted in 1982 in the Kaybob South Beaverhill Lake Unit 1 and in 1984 in the Kaybob South Beaverhill Lake Unit 2 with full blow down of the reservoir commencing at that time.

Hudson's Bay stated that in 1981 the combined production for both plants would drop below 1000 long tons per day. The operation would then fall into the 400 to 1000 long tons per day category of the guidelines which requires sulphur recovery efficiencies of 96 to 98 per cent, a range within which the existing facility can operate.

The applicant estimated that a tail gas sulphur recovery unit to increase the recovery of the Kaybob plants to 98 per cent would cost $3,470,000 and would increase operating costs by $350,000 per year. Increasing the sulphur recovery to 99 per cent would require an estimated capital cost of $5,800,000 with an increase in annual operating costs of $715,700. Hudson's Bay argued that in either case the capital expenditure and associated operating cost are not justified for the conservation of a relatively small amount of sulphur in view of the forecasts for an over-supply of sulphur.

Hudson's Bay submitted a cash flow analysis of the sulphur recovery operations for the period 1968 to 1992. At present sulphur recovery levels this analysis indicated an undiscounted cash position at the end of reservoir blow down in 1992 of -$6,843,172. Installing facilities to increase the recovery to 98 per cent would cost an additional $5,795,567 resulting in an undiscounted cash position in 1992 of -$12,638,739. Installing facilities to increase the sulphur recovery to 99 per cent would cost a further $4,713,826 resulting in an undiscounted cash position in 1992 of -$17,352,565. Hudson's Bay concluded that the sulphur recovery operations would be increasingly uneconomic with an increase in sulphur recovery efficiency and that additional sulphur recovery could not be justified on economic grounds.

For the purpose of its economic analysis the applicant assumed a sulphur price of $6.00 per long ton F.O.B. railcar at the plant in 1972 declining to $4.00 per long ton by 1978 and remaining at $4.00 over the remaining life of the scheme. It assumed the ratio of sulphur sales to total sulphur production would remain the same in the future as experienced to date at 0.8190 for Kaybob Plant 1 and 0.7041 for Kaybob Plant 2. Present railway arbitrary payments of $2.05 per long ton of sulphur shipped and slating and loading charges of 94.5¢ per long ton were assumed to apply through the life of the project. Plant netback sulphur prices were therefore assumed to be approximately $3.00 per long ton in 1972 declining to $1.00 per long ton by 1978 and remaining at this level thereafter. Following the hearing Hudson's Bay stated that slating and loading costs had increased by 23.5¢ per long ton to $1.18 per long ton which would place an additional economic burden on the sulphur recovery operations.

Hudson's Bay stated that it did not expect to sell sulphur from stockpile since the estimated selling costs including the railway arbitrary payment, handling, melting, slating and loading costs of $4.80 per long ton would exceed the forecast price F.O.B. railcar at Kaybob of $4.00 per long ton, after 1978, resulting in a loss of $0.80 per long ton.

Hudson's Bay stated that its analysis indicated that if sulphur prices were 1.5 times those specified in the forecast the present operation would yield a discounted rated of return of eight per cent. Sulphur prices 1.9 times those specified in the forecast would be required for the present operation after installation of a tail gas clean up process capable of 98 per cent recovery to yield a rate of return of eight per cent.

Hudson's Bay stated that should an exemption be granted it would intensify a program for improvement of sulphur recovery levels. This would include the installation of additional process control equipment and investigation of various unit functions to optimize the efficiency of the operation.

It stated that this optimization would result in an increase in plant sulphur recovery efficiency to approximately 97 per cent and that it would accept an amendment of the Board's approval to require a sulphur recovery of 97 per cent if the application should be granted.

Hudson's Bay also proposed to install monitoring stations around the plant which would continuously transmit to the plant control room the ground level sulphur dioxide concentrations to which the area is exposed so that the raw gas inlet rate could be adjusted to ensure that acceptable levels are not exceeded. It stated that it would also conduct an infra-red aerial photograph survey of the area surrounding the plant to measure vegetation stress and provide a base measurement for determining if degradation of the environment occurs in the future.

SUBMISSION OF CHEVRON

Chevron made a submission in support of the application of Hudson's Bay submitting that the application should be approved because:

(1) In Chevron's view there is no justification for the

recovery of the additonal sulphur on a conservation basis, since any additional sulphur recovered would be stored for at least 10 years due to the surplus world sulphur supply situation. It stated that even if the sulphur were sold, the cost of upgrading the plant would be such that, at current sulphur prices, no payout could be realized.

(2) In Chevron's view so long as the total ground level concentration of sulphur dioxide emitted by all industries in an area remains within the presently prescribed safe limits, there is no indicated justification for imposition of more stringent standards than those which existed at the time the plant was approved.

VIEWS OF THE BOARD

By interpolation based on a maximum inlet capacity of [illegible],180 long tons per day the Board interprets the minimum sulphur recovery guidelines to require a sulphur recovery of 98.4 per cent. However, considering the forecast decline in sulphur production commencing in 1976 the Board is of the opinion that a sulphur recovery level of 98 per cent would meet the guideline requirements and therefore considers the application to be one for exemption from this level.

As stated in Decision 73-2 the Board intends the minimum sulphur recovery efficiency guidelines to be an overall control of plant operations beyond, and essentially independent of, local environmental protection. The Board believes that, even though by present ground level standards the environmental aspects of a plant operation might be satisfactory, maximum practical sulphur recovery should be achieved both in the interests of conservation of a natural resource and to minimize overall sulphur dioxide emissions and the potential for adverse environmental effects on a broad scale. The Board stated that the sulphur recovery level should be as high as practical having regard for both economics and sulphur recovery technology.

Using the method of analysis described in Decision 73-2 the Board examined the economics of the operation of the sulphur recovery facility at the subject plant to determine the rate of return after 1974. The Board calculated that approximately $3,160,000 of past sulphur plant investment should be carried forward to January 1, 1975 as "unrecovered" investment for the existing facility. The Board estimated that an investment of approximately $3,540,000 would be required to increase the sulphur recovery to 98 per cent. This is approximately equal to the $3,470,000 capital cost estimated by Hudson's Bay. The Board's economic analysis was therefore based on a total investment in 1975 of $6,700,000. The Board estimated sulphur plant operating costs, after installation of a tail gas clean up plant, in 1975 of $1,054,000 and escalated these costs at 3 per cent per year with some allowance made for decline in operating costs later in the life of the scheme due to declining production. The Board's operating costs for 1975 are lower than the $1,236,287 cost submitted by the applicant but exceed those submitted by the applicant in later years. Over the period 1975 to 1990 the

Board estimates total sulphur plant operating costs of $14,036,000 while the applicant estimates total sulphur plant operating costs during the same period of approximately $12,600,000. The Board included an annual arbitrary railway payment of $496,000, ending December 31, 1982, in its economic analysis to account for rail payments. This cost is less than that submitted by the applicant but the Board understands it to be the current arbitrary rail cost. The Board based its analysis on the applicant's revised estimate of sulphur production, submitted to the Board after the hearing, and on its own forecast of percentage sulphur sales and sulphur price. The Board's sulphur price forecast is somewhat more optimistic than that indicated in Decision 73-2, dated January 25, 1973. The Board has revised its sulphur price forecast in view of recent developments in the sulphur market which could only enhance the economics of the sulphur plant operation. The data used in the Board's economic evaluation is given on Table 1.

The Board's evaluation indicated a discounted rate of return before taxes of 7.7 per cent at an illustrative royalty rate of 25 per cent. The Board carried out a similar evaluation using the applicant's capital and operating costs but the Board's estimate of railway arbitrary payments, percentage sulphur sales, sulphur prices and a royalty rate of 25 per cent. This evaluation indicated a discounted rate of return of 8.5 per cent.

The Board concludes that the sulphur recovery operation would remain marginally profitable with an increase in the sulphur recovery efficiency to 98 per cent and that requiring an increase in the sulphur recovery efficiency is desirable.

DECISION

The Board denies the application by Hudson's Bay for exemption of the Kaybob Unit 1 and 2 Processing Plant from the minimum sulphur recovery efficiency guidelines and requires that the plant meet a sulphur recovery requirement of 98 per cent after December 31, 1974. Amendment of Approval No. 1415 and Approval No. 1730 are being issued concurrently with this decision.

The Board expects that, in accordance with Informational Letter No. IL 71-29, Hudson's Bay will apply prior to May 31, 1973, unless a later date is stipulated by the Board, for approval of the proposed modifications necessary to meet the 98 per cent requirement.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

DATED at Calgary, Alberta
April 23, 1973

Table 1

Data Used for Board Evaluation of Kaybob Sulphur Recovery Plant Economics

nvestment $\$ \times 10^3$	Annual Operating* Cost $\$ \times 10^3$	Annual Sulphur Production LT $\times 10^3$	Percentage of Sulphur Sold	Plant Netback Sulphur Price \$/LT
3,540	1,550	653	50	9.00
	1,581	639	50	10.00
	1,615	579	50	11.00
	1,648	485	52	12.00
	1,682	424	54	12.00
	1,718	311	56	12.00
	1,125	259	58	12.00
	1,145	212	60	12.00
	668	146	60	12.00
	688	139	60	12.00
	709	134	60	12.00
	730	131	60	12.00
	751	131	60	12.00
	774	131	60	12.00
	798	121	60	12.00
	822	119	60	12.00

ides railway payments

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-8
Application No. 6719

EXPANSION OF THE GAS HANDLING AND PROCESSING FACILITIES IN THE NEVIS AREA

THE APPLICATION AND HEARING

Gulf Oil Canada Limited applied under section 38, subsection (1), clause (b) of The Oil and Gas Conservation Act for expansion of the gas handling and processing facilities in the Nevis, Stettler, Fenn-Big Valley, Clive-Alix and Erskine areas. The applicant proposed to increase the inlet capacity of the Nevis Gas Plant, located in the North-east Quarter of Section 33, Township 38, Range 22, West of the 4th Meridian, from 116 million cubic feet per day (MMcfd) of plant feed stock to 125 MMcfd and to increase the maximum hydrogen sulphide inlet rate from 7.75 MMcfd to 8.09 MMcfd. The sulphur recovery efficiency of the Nevis Plant would be increased from 95 per cent to 95.5 per cent and the maximum permitted sulphur dioxide emission rate would decrease from 29.0 long tons per day (LTD) to 27.4 LTD. The sulphur dioxide would continue to be emitted to the atmosphere through the existing 320-foot incinerator stack.

The capacities of the Fenn-Big Valley, Stettler, Erskine and Clive-Alix Satellite Gas Processing Plants would also be expanded. The inlet capacity of the Fenn-Big Valley Satellite Plant, located in the South-west Quarter of Section 14, Township 36, Range 20, West of the 4th Meridian, would be increased from 12.66 MMcfd to 28.7 MMcfd (25.7 MMcfd of solution gas and 3.0 MMcfd of sweet non-associated gas); the Stettler Satellite Plant, located in Legal Subdivision 13 of Section 10, Township 38, Range 20, West of the 4th Meridian, from 1.23 to 2.80 MMcfd; the Erskine Satellite Plant, located in Legal Subdivision 5 of Section 7, Township 39, Range 20, West of the 4th Meridian, from 1.50 to 4.15 MMcfd; and the Clive-Alix Satellite Plant, located in Legal Subdivision 4 of Section 9, Township 40, Range 24, West of the 4th Meridian, from 5.0 to 14.8 MMcfd.

An intervention in opposition to the application was filed by the County of Red Deer; but, the County was not represented at the hearing. A resident of the area, Mr. F. Salterman, did not file an intervention but spoke in opposition to the application at the hearing.

The application was heard on January 30, 1973, by D.R. Craig, P. Eng., and J.I. Strong, P. Eng. Their report to the Board, in accordance with section 9 of The Energy Resources Conservation

Act, was accepted by the Board and incorporated herein.

APPEARANCES

The following appeared at the hearing;

	Represented by	Abbreviation Used in Report
Gulf Oil Canada Limited	R.E. Pauls, P. Eng. R.L. Clarke, P. Eng. R.K. Craig, P. Eng. I.R. Dunnet J.G. Gainer, P. Eng. H.T. Guyn, P. Eng. J.S. Hart, P. Eng. A. Kowalchuk, P. Eng. J.R. Moore, P. Eng. J.C. Stamberg, P. Eng. R.K. Agrawal, P. Eng. (of Intercomp Resource Development and Engineering Ltd.)	Gulf
F. Solterman	F. Solterman	
Department of the Environment	R. Beaty	Department
Board Staff	R.B. Dunbar, P. Eng. K.D. Adams, P. Eng.	

DEFINITION OF ISSUES

The Board considers the following to be the main issues:

(a) the conservation of solution gas in the Fenn-Big Valley, Stettler, Erskine and Clive-Alix Areas,

(b) the conservation features of the Nevis Gas Processing Plant,

(c) the pollution control features of the satellite processing plants, and

(d) the pollution control features of the Nevis Gas Processing Plant.

SOLUTION GAS CONSERVATION

Views of Gulf

(1) Fenn-Big Valley and Stettler South

Gulf submitted that the solution gas capacity of the Fenn-Big Valley Satellite Plant would be increased from 10.0

to 25.7 MMcfd. The maximum solution gas production expected from the instantaneous overproduction of oil was 25.8 MMcfd. This rate was limited by the oil handling facilities being proposed for the Stettler South and Fenn-Big Valley Fields. The gas conservation facilities proposed were designed to accommodate all of the gas production from the two fields served by the gas conservation facilities.

Gulf submitted that to accommodate maintenance, repair and overhaul of the gas conservation facility without loss of oil production some 5.8 per cent of the gas produced in the Stettler South and Fenn-Big Valley Fields would be flared on a yearly basis. Gulf therefore proposed that the flaring limitation be at least ten per cent.

(2) Stettler

Gulf submitted that the Stettler Satellite Plant would be expanded from a capacity of 1.23 to 2.80 MMcfd. At peak rates of oil production the gas production was expected to be some 2.90 MMcfd. The latter would be all the gas production to be expected from the Stettler Field during peak oil production. The oil production facilities in the Stettler Field would be modified slightly to permit the accommodation of the higher oil production.

Gulf submitted that to accommodate the maintenance and overhaul of the gas conservation facilities, some 8.9 per cent of the gas production would be flared. Gulf proposed a flare allowance of ten per cent for the Stettler Field.

(3) Erskine

Gulf submitted that the capacity of the Erskine Satellite Plant would be increased from 1.50 to 4.15 MMcfd. No modifications were proposed for the oil production facilities. Gulf proposed that the flaring allowance be five per cent for the Erskine Field.

(4) Clive-Alix

The Clive-Alix Satellite Plant capacity would be increased from 5.00 to 14.80 MMcfd. The peak gas rate in the future was forecast at 15.00 MMcfd. The Clive-Alix Fieldgate system would be modified to handle the expected additional oil production. Gulf proposed a ten per cent flaring allowance for the Clive-Alix gas conservation system.

Views of the Board

The Board accepts that the capacity of the gas conservation facilities after the proposed expansion has been undertaken will be adequate in the Fenn-Big Valley system having regard to the average capacity of the proposed fieldgate system. The Board notes that in the Stettler and Clive-Alix systems a minor short fall may exist in the capacity of the gas conservation system after the proposed expansion has been undertaken. The capacity of the Erskine gas conservation facilities appears adequate after the proposed expansion is completed.

The Board notes that the design capacity of the proposed expansions of the gas conservation facilities in the Fenn-Big Valley, Stettler South, Stettler, Clive-Alix and Erskine systems was based upon the continuing conservation of gas from the wells now tied into the existing systems together with the gas from those wells now exempt. A review of the exemptions has been undertaken by the Board separately from this application.

The Board recognizes that the flaring limitations vary from 20 per cent for the Fenn-Big Valley Field, 10 per cent for the Stettler South, Stettler, Clive and Alix Fields, to five per cent for the Erskine Field. The Board is of the opinion that no clear reason exists for the variation in flaring limitations but believes this matter should be considered separately from this application.

NEVIS PLANT CONSERVATION FEATURES

Views of Gulf

Gulf proposed to increase the Nevis Plant inlet capacity from 116 MMcfd to 125 MMcfd and to increase the maximum hydrogen sulphide inlet rate from 7.75 MMcfd to 8.09 MMcfd. At maximum plant capacity the residue gas sales rate would increase from 70 MMcfd to 94 MMcfd, the propane production from 1,768 barrels per day (BPD) to 3,633 BPD, the butanes production from 1,361 BPD to 2,423 BPD, the pentanes plus production from 1,208 BPD to 1,684 BPD and the sulphur production from 278 to 290 long tons per day (LTD).

Gulf stated that hydrocarbon conservation would be essentially complete. Flaring would not occur under normal operating conditions. Gulf stated that several features would be included in the design of the plant expansion to minimize flaring and eliminate some of the problems which resulted in flaring in the past.

It was proposed that the gas compression capacity be increased from 3,288 to 5,370 horsepower and that one 990 horsepower compressor be installed as a standby unit for sour gas boosting requirements. Refrigeration compression would be increased from 2,012 to 3,257 horsepower and would be sufficient to permit the shut down of one unit for maintenance without upsetting the plant. Spare compressor capacity had not been available in the past so that the inclusion of spare capacity as part of the expansion would result in reduced flaring.

Gulf stated that the installation of a more elaborate communication network would allow the central plant operator to monitor the performance of the various satellite compressor plants. This facility would reduce the frequency of plant upsets resulting from field operating problems.

Gulf submitted that liquid slugging in the Clive-Alix raw gas transmission line had been the cause of much of the past flaring due to variability in gas flow rates and plant feed composition. At the proposed increased flow rate and with no change in the line size Gulf expected that this problem would be eliminated.

Gulf proposed to increase the minimum sulphur recovery efficiency from the present 95 per cent level to 95.5 per cent. The existing two stage No. 1 Sulphur Plant would be retired and replaced with a larger three stage No. 4 Sulphur Plant. The existing two stage No. 2 and No. 3 Sulphur Plants would not be modified. Gulf stated that, at the proposed maximum sulphur inlet rate of 304 LTD, the 95.5 per cent recovery would meet the requirements of the Board's sulphur recovery efficiency guidelines. The guidelines require a sulphur recovery of 94 to 96 per cent for plants processing favourable quality acid gas containing from 100 to 400 LTD of sulphur.

The sulphur plant tail gas stream containing the unrecovered sulphur would be incinerated and exhausted to the atmosphere through the existing 320-foot incinerator stack. At the proposed recovery level of 95.5 per cent the maximum sulphur dioxide emission rate would be 27.4 LTD. Gulf stated that installing a third conversion stage to the No. 2 and No. 3 Sulphur Plants would cost from $300,000 to $400,000 and would reduce the maximum sulphur dioxide emission rate from 27.4 LTD at 95.5 per cent recovery to 24.4 LTD at a 96 per cent recovery or 21.3 LTD at a 96.5 per cent recovery.

Mr. F. Solterman queried Gulf on the possibilities of compressing flared gas streams and returning them to the inlet of the plant and injecting the sulphur plant tail gas stream to an underground formation. In response to his questions Gulf stated that it proposed to provide standby compressor capacity to ensure that flaring would be minimal and that injection of plant tail gas to an underground formation presented technical problems and would be very costly. Gulf calculated that injection of the tail gas stream would require an additional 20,000 horsepower of compressor capacity, making the cost of this proposal prohibitive.

Views of the Board

The Board is generally satisfied with the conservation aspects of the Nevis Plant. Proposed hydrocarbon and sulphur conservation levels appear to be satisfactory.

The Board agrees with Gulf that the 95.5 per cent sulphur recovery efficiency proposed would meet the Board's sulphur recovery efficiency guidelines. Gulf's assessment of underground disposal of the tail gas was examined by the Board and, although the Board calculated that somewhat less horsepower would be required, the Board concurs with Gulf's conclusion that this proposal for pollution abatement would not be reasonable in this case. It is the Board's view that if further reduction in emissions were necessary it could be done more efficiently and at less expense by installing additional sulphur recovery equipment.

SATELLITE PLANTS POLLUTION CONTROL FEATURES

Views of Gulf

Gulf stated that the satellite plants adjacent to the Fenn-Big Valley, Stettler, Erskine and Clive-Alix Fieldgates would be expanded and modified to handle the increased solution gas and non-associated gas volumes. Gas compression horsepower would be increased at all four plants. The refrigeration facilities at the Fenn-Big Valley and the Stettler Plants would be expanded. Molecular sieve dehydration facilities would be installed at the Erskine Plant and the existing molecular sieve unit at the Clive-Alix plant would be replaced with a larger unit. New enlarged flare stacks would be installed at the Fenn-Big Valley, Stettler and Erskine plants to handle sour gas flaring. The existing Clive-Alix flare stack would be modified to burn smokelessly. Burn pits would no longer be used.

Gulf stated that under normal operating conditions flaring would not occur at the satellite plants as all vapours would be compressed and delivered to the Nevis Plant. Calculations submitted by Gulf indicate that the proposed new flare stacks at the Stettler, Fenn-Big Valley and Erskine plants would not result in ground level sulphur dioxide concentrations exceeding the 0.20 parts per million standard. At the maximum inlet rate to the Clive-Alix plant Gulf's calculations indicated that flaring all of the sour gas could result in a sulphur dioxide ground level concentration of 0.68 parts per million. Gulf stated that flaring at the Clive-Alix plant would be on an emergency basis only and that facilities at the plant and in the field would allow shutdown within the one hour limitation required for emergency flaring. Gulf stated that a new flare stack 300 feet in height would be required to achieve a calculated maximum ground level sulphur dioxide concentration of 0.20 parts per million, and that the expenditure was not warranted in view of Gulf's emergency response capability.

Gulf stated that all liquid wastes from the satellite plants would be contained and injected to a subsurface formation.

Views of the Board

The Board is generally satisfied with the pollution control features of the satellite processing plants with the exception of the proposed continued use of the present flare stack at the Clive-Alix plant. Board staff calculations indicate a maximum ground level sulphur dioxide concentration due to emergency flaring at this location of 0.52 parts per million. The Board is of the view that, although sour gas flaring might be infrequent, the emergency flare system should be designed to achieve a maximum ground level sulphur dioxide concentration of 0.20 parts per million under the most adverse conditions.

The Board has considered the air quality monitoring requirements for the satellite plants and believes that an expansion of the current monitoring program is warranted. At the present time field monitoring consists of the use of three exposure cylinder stations at the Fenn-Big Valley plant, two stations at the Stettler Plant and no stations at either the Erskine or the Clive-Alix Plant. Having regard for the flaring levels anticipated by Gulf the Board considers that the monitoring should be increased to require four exposure cylinder stations at the Fenn-Big Valley Plant, two stations at the Stettler Plant, two stations at the Erskine Plant, and 12 stations at the Clive-Alix Plant. The results of the exposure cylinder monitoring should then be used to determine whether continuous monitoring is necessary and where and when it should be carried out.

POLLUTION CONTROL FEATURES AT NEVIS PLANT

Views of Gulf

Gulf stated that unrecovered sulphur would be emitted as sulphur dioxide through the existing stack at rates up to 27.4 LTD, a reduction from the presently approved maximum rate of 29.0 LTD.

Gulf submitted that at the proposed maximum emission rate the calculated maximum ground level concentration of sulphur dioxide in the area of the plant was less than that permitted by Provincial standards except at the top of a hill located some two miles north-west of the plant. The calculations, based on the Pasquill method, indicated a half hourly concentration on the hill top could be as high as 0.27 parts per million, compared to the Provincial standard of 0.20 parts per million. The nearest resident lives approximately one-half mile from the top of this hill.

Gulf stated that it believed the Pasquill calculation method to be overly conservative and that observed concentrations would be considerably less than those predicted. It submitted the results of a simulation study carried out using a three dimensional air pollution numerical model which indicated maximum concentrations of 0.12 parts per million under those conditions which gave a concentration of 0.27 parts per million by the Pasquill method. Gulf stated that the numerical model more accurately predicts pollutant concentrations in hilly terrain than does the Pasquill method.

Gulf stated that the Pasquill calculations indicate that concentrations exceeding the standard would occur only when winds exceeding 10 miles per hour in velocity blew from the south-east direction. It submitted that a review of wind observations made at the plant over a 27-month period indicated that winds in excess of 10 miles per hour from the south-east octant occur only three per cent of the time. Its observations indicated the river valley to have a significant affect on the wind flow in the area and that because of this local effect the wind distribution at the plant varies considerably from the wind distribution at other locations in the vicinity of the plant.

Gulf stated that its air quality monitoring had not indicated pollutant concentrations in excess of Provincial standards. It stated that it had not conducted any continuous monitoring on the hill north-west of the plant due to lack of an available power supply.

Gulf stated that a calculated concentration of 0.20 parts per million could be achieved either by constructing a higher stack or by reducing the sulphur dioxide emission rate by increasing the sulphur recovery efficiency. Its calculations indicated that either a 60-foot higher stack or a sulphur recovery of 96.5 per cent would be required.

On the basis of its model study, meteorological data which indicate that the winds blowing towards the hill occur only three per cent of the time, and past monitoring which indicated low concentration of sulphur dioxide, Gulf requested that it not be required to increase its stack height or reduce its emission rate to achieve the maximum calculated concentration of 0.20 parts per million using the Pasquill method. It stated that it would be prepared to carry out additional air quality monitoring on the hill to substantiate its contention that actual sulphur dioxide concentrations would not exceed the standard at that point.

Gulf proposed to continue to use the existing 100-foot flare stack for emergency flaring. It calculated maximum ground level sulphur dioxide concentrations due to sour gas flaring of 0.99 parts per million on a hill approximately one-half mile north-west of the plant. It stated that this concentration is within the permitted maximum of 1.0 parts per million for emergency flaring periods less than one hour in duration and that all of the incoming streams could be shut in quickly during an emergency to reduce the flaring rate. Gulf stated that, if no supplemental fuel gas is injected, the emergency flare stack would have to be 255 feet high in order to maintain a maximum sulphur dioxide concentration of 0.20 parts per million as calculated by the Pasquill method.

The applicant stated that the existing flare stack is designed to burn smokelessly utilizing a manually controlled forced air system. Gulf stated that the operation of this facility has been relatively satisfactory but that some improvement is required.

Gulf stated that the pentanes plus storage tank vent line would be connected to the flare system so that any vapours that may evolve from the tank would not be vented directly to the atmosphere. It stated that any liquid hydrocarbons entering the plant drain system would be collected and returned to the process. Sulphur dust would not be a problem as all sulphur shipments would be made in liquid form. Any surplus sulphur would be stockpiled.

Gulf stated that waste liquids would not normally flow to the lagoon. All liquid wastes would be collected and injected to a subsurface disposal well. Muddy water from the plant cyclone separators, used to clarify the raw water, would be returned to the river during periods of high river flows.

On questioning regarding complaints about the plant from local people, Gulf stated that in its opinion complaints have been minimal and the complaint history is satisfactory.

Views of F. Solterman

Mr. F. Solterman stated that in his opinion the application represents construction of a new plant, not a plant expansion, and that additional plants should not be permitted in the area. He stated that continuous monitoring should be carried out on the hill north-west of the plant. He questioned the wind data submitted by Gulf, stating that winds frequently blow towards the hill north-west of the plant. Mr. Solterman questioned why flared gas streams couldn't be cycled back to the plant inlet line or injected into an underground formation.

Views of the County of Red Deer

The County of Red Deer was not represented at the hearing. However, in its submission, filed prior to the hearing, it expressed concern with the proposed sulphur recovery efficiency and sulphur dioxide emission rate. It stated that the sulphur recovery efficiency should be increased to reduce the sulphur dioxide emission rate to not more than that which would be achieved if the sulphur recovery was 95.5 per cent at the present plant throughput. The maximum sulphur dioxide emission rate under these conditions would be 26.1 LTD and the required sulphur recovery efficiency would be 95.7 per cent.

Concerns of the Department

The Department stated that it would like to examine the calculations of ground level sulphur dioxide concentrations made using the numerical model more completely before it rules on whether this method of calculation is more acceptable than the Pasquill method now being used. It is interested in and wished to encourage development respecting dispersion calculation methods but requires more time and data to evaluate the matter fully. The Department stated that in its opinion examination of more cases under different atmospheric stability and wind conditions would be required to fully evaluate the subject application using the numerical model.

In regard to calculated sulphur dioxide concentrations in excess of 0.20 parts per million under emergency flaring conditions, the Department stated that ambient concentrations not exceeding 0.20 parts per million must be maintained. It stated that in the past it had permitted calculated concentrations up to 1.0 parts per million for emergency flaring not exceeding one hour in duration but it would be reassessing emergency flaring requirements and might be lowering the permitted maximum calculated concentration.

Views of the Board

Using the Pasquill calculation method the Board calculates a maximum sulphur dioxide concentration at ground level of 0.25 parts per million at the proposed maximum sulphur dioxide emission rate of 27.4 LTD. Calculated concentrations in excess of 0.20 parts per million would occur at the top of a hill approximately two miles north-west of the plant. Its calculations indicate that, to reduce the calculated maximum concentration to 0.20 parts per million, a sulphur recovery efficiency of 96.4 per cent and a maximum sulphur dioxide emission rate of 21.9 LTD or an 85-foot increase in the stack height would be required. The Board estimates that the capital cost of either alternative would be in the order of $300,000.

The Board recognizes the shortcomings of the Pasquill calculation method for areas of hilly terrain and the advantages of a sophisticated three dimensional numerical model such as that used by Gulf. However, the Board does not believe that sufficient evidence has been presented in this case to prove the superiority of the numerical model over the Pasquill calculation method. The Board believes that it would be necessary to evaluate several meteorological conditions using the model to establish the actual calculated maximum concentrations in the general plant vicinity. It considers the model's results for those conditions indicated to be most adverse by the Pasquill method to be only a partial analysis of the sulphur dioxide dispersion problem.

The Board has examined wind data for the general area as measured at stations in Coronation, Lacombe and Penhold. These data indicate winds from the south-east octant do occur from 11 to 15 per cent of the time. More localized wind data were not studied.

The Board also examined the results of ambient air sulphur dioxide concentration measurements made in the plant vicinity in the last two years. This monitoring has indicated no readings in excess of the air quality standards. On two occasions concentrations approximately equal to the new air quality standards were detected.

In view of the results of past monitoring which indicated no measured concentrations in excess of the present standard and the fact that the maximum sulphur dioxide emission rate of the plant is to be reduced slightly, the Board is of the opinion that modifications to meet the calculated ground level sulphur dioxide concentrations standard need not be required at this time. The Board concludes, however, that additional monitoring should be carried out on the hill north-west of the plant because of the high calculated concentrations and the need for remedial action or reconsideration if the Provincial standards are not met.

The Board notes that the calculated maximum ground level sulphur dioxide concentration of 0.99 parts per million that could occur during emergency flaring of sour gas is within the previously permitted maximum calculated concentration of 1.0 parts per million for emergency flaring periods of less than one hour in duration. The Department has not issued new calculation standards, but the Board believes that it would be desirable for Gulf to design the emergency flare system to achieve a maximum calculated concentration within the 0.20 parts per million standard. This could be accomplished by either increasing the stack height or by adding supplemental fuel gas to the existing flare system during periods of sour gas flaring.

The Board has not been satisfied with the control of smoke emissions from the flare stack in the past and believes that further improvements are necessary. The Board recognizes that Gulf is taking action to reduce flaring and control smoke emissions and expects these matters to be successfully dealt with in the very near future.

DECISION

The Board grants the application by Gulf for expansion of the gas handling and processing facilities in the Nevis area subject to the conditions that:

1. the minimum sulphur recovery efficiency at the Nevis Plant be set at 95.5 per cent,

2. the maximum sulphur dioxide emission rate at the Nevis Plant be set at 27.4 LTD,

3. the emergency flare systems at the Nevis Plant and the Clive-Alix Satellite Plant be designed to achieve a maximum calculated concentration of sulphur dioxide at ground level of 0.20 parts per million,

4. the air quality monitoring network for the Nevis Plant be expanded to provide for 16 exposure cylinder stations and one continuous monitor to be operated for 12 months of each year, and

5. the air quality monitoring networks for the satellite plants be expanded to provide for additional exposure cylinder monitoring stations as described earlier in this decision.

The Board requires that Gulf report to it regarding the manner in which the Nevis Plant and the Clive-Alix Plant emergency flaring facilities would be modified to achieve a calculated maximum sulphur dioxide concentration of 0.20 parts per million and the manner in which the air quality monitoring networks would be expanded.

Approval No. 1876 is being issued concurrently with this decision.

ENERGY RESOURCES CONSERVATION BOARD

D R Craig

D.R. Craig, P. Eng.
Vice-Chairman

Dated at Calgary, Alberta
May 3, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-9
Application No. 6760

APPLICATION FOR EXEMPTION FROM THE SULPHUR RECOVERY GUIDELINES STRACHAN GAS PLANT

THE APPLICATION AND HEARING

Gulf Oil Canada Limited submitted Application No. 6760 to exempt the Strachan Gas Plant, located in Section 35, Township 37, Range 9, West of the 5th Meridian, from the minimum sulphur recovery efficiency guidelines provided in Board Informational Letter No. IL 71-29. The Strachan Gas Plant is presently permitted to process a maximum equivalent sulphur inlet rate of 955 long tons per day and is required to recover as elemental sulphur a minimum of 96 per cent of the sulphur delivered to the plant. IL 71-29 requires that a plant with an inlet rate of between 400 and 1000 long tons per day of sulphur, processing a favourable quality acid gas, recover 96 to 98 per cent of the sulphur delivered to the plant after December 31, 1974.

Interventions respecting the application were filed as follows:

(a) a single intervention signed by 51 residents of the general Strachan area,

(b) the Canadian Forestry Service and the Environmental Protection Service of Environment Canada,

(c) Mr. Richard Gabler, a resident of the area, and

(d) the Red Deer Regional Planning Commission.

The Red Deer Regional Planning Commission was not represented at the hearing.

The application was heard in the Provincial Building, Rocky Mountain House, on January 10, 1973 by examiners G. J. DeSorcy, P. Eng., N. A. Strom, P. Eng. and the late P. D. Larbalestier, P. Eng.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Gulf Oil Canada Limited	R. E. Pauls, P. Eng. R. L. Clarke, P. Eng. A. Kowalchuk, P. Eng. J. A. Law, P. Eng. J. G. Gainer, P. Eng.	Gulf
Residents of the Area	R. S. McDonald D. M. McDonald L. L. Kennedy G. R. Graham R. Gabler	
Canadian Forestry Service and Environment Protection Service of Environment Canada	R. A. Blauel A. Hazra	Environment Canada
Alberta Department of the Environment	J. C. Lack R. Stetson, P. Eng.	Department
Energy Resources Conservation Board Staff	R. B. Dunbar, P. Eng.	

Alberta Department of the Environment staff participated with Board staff in examination of the applicant and the interveners but did not file a submission or present an opinion respecting the application at the hearing.

DEFINITION OF THE ISSUE

The main issue of the application is the future sulphur recovery efficiency to be required of the subject plant. Board Approval No. 1349, as amended January 5, 1973, requires a minimum sulphur recovery efficiency of 96 per cent while Informational Letter No. IL 71-29 requires a recovery in the range 96 to 98 per cent to apply after December 31, 1974. Interpolation of the guidelines, based on the maximum sulphur inlet capacity of 955 long tons per day, results in a required sulphur recovery efficiency of 98 per cent. The issue is therefore whether the sulphur recovery efficiency to apply after December 31, 1974 should be 96 per cent or 98 per cent, or some intermediate value.

In addition to considering the sulphur recovery efficiency to be required at the plant, the examiners heard considerable evidence respecting the overall conditions of the environment in the general Strachan Area and have dealt with this matter later in the report.

SUBMISSION OF THE APPLICANT

Gulf based its request for exemption from the sulphur recovery efficiency guidelines on the adverse economics of adding a tail gas recovery process to the plant to increase the recovery beyond 96 per cent and on the ambient air quality resulting from the operation of the present plant facilities.

Gulf stated that sulphur recoveries of 98 per cent cannot be achieved on a regular basis with Claus sulphur plants and thus that a tail gas recovery process would be required to accomplish such a recovery. In Gulf's opinion the existing facilities are capable of recoveries in the range of 96.5 to 97 per cent for short durations but are not capable of sustaining these recoveries over significant periods of time. Gulf stated that a fourth stage of Claus conversion would not significantly increase average sulphur recovery.

The applicant stated that it considers the cost of installing tail gas sulphur recovery facilities to be uneconomic. It estimated the capital cost of the necessary equipment to be $2,200,000 and that associated additional operating costs would be $220,000 per year. Gulf stated that such expenditures could not be justified since its analysis indicates the existing sulphur recovery facilities would yield a net cash return of -$1,084,000 (discounted at 8 per cent), and that the net cash return would become -$2,513,000 (discounted at 8 per cent) if it was necessary to install the tail gas sulphur recovery facilities. Gulf based its economic evaluation on commencement of sulphur sales in 1982, a sulphur price of ten dollars per long ton and continuation of sulphur sales at unit train rates until the sulphur stockpile is depleted in 1991. It stated that sulphur sales could not commence until the price was sufficient to warrant construction of sulphur shipping facilities into the area. It estimated that this would require a sulphur price of ten dollars per long ton and sulphur sales of 400,000 to 600,000 long tons per year. Gulf stated that if it was shipping sulphur from the area on its own at unit train rates sulphur shipping costs to Rocky Mountain House would be approximately five dollars per long ton.

Gulf forecasts shut-down of the plant in 1988, which is earlier than had originally been anticipated, due to substantial downward revision of the estimated gas reserve in the Strachan D-3 A Gas Pool, the only pool now connected to the plant. The gas reserve estimate of that part of the Strachan D-3 A Pool to be processed by the subject plant was originally some 1,900 billion cubic feet (Bcf) and was based on a volumetric calculation. Using production data, a material balance calculation of the reserve now indicates it to be 1,076 Bcf. The reserves are projected to be produced at an average raw gas rate of 250 million cubic feet per day (MMcfd). This is a rate of withdrawal from the reservoir of one MMcfd for each 4.3 Bcf of reserves, higher than the normal contract rate of take.

Gulf was questioned regarding the possibility of the rate of take under the existing gas sales contract being reduced to reflect the new reserve estimate for the field. It stated that this is a possibility that would depend on its negotiations with the gas purchaser.

In reply to questioning, Gulf stated that it had no definite plans to process gas from other than the Strachan D-3 A Pool at the plant in order to extend its life. It stated that it is not participating in the drilling currently taking place in the area. Gulf stated that it does have a shut-in sour Ricinus gas reserve south of the plant, but that there are no plans to produce this gas at the present time due to the adverse economics of processing dry sour gas at the Strachan Plant. Gulf acknowledged that higher gas and sulphur prices could make these projects economic.

Gulf emphasized that it is not evading its responsibilities respecting protection of the environment. It is of the opinion that it is causing no harm to the environment at current recovery levels and that increasing the recovery to 98 per cent is not required.

Gulf stated that air quality monitoring in the vicinity of the plant has not indicated sulphur dioxide or hydrogen sulphide concentrations in excess of acceptable levels. Gulf submitted the results of a plume survey conducted at the plant and stated that it plans other environmental studies such as further infrared photo surveys and soil studies.

In response to questioning by the interveners Gulf stated that it would be prepared to make the results of any special studies carried out at the plant available to those who desire them. It stated that flaring at the plant is infrequent and usually of short duration and that off-site air monitoring instruments are calibrated once per month.

SUBMISSIONS OF THE INTERVENERS

Mr. R. S. McDonald, speaking on behalf of himself and other residents of the Strachan Area who signed the general submission, stated that the expenditure necessary to increase the sulphur recovery to 98 per cent would be a small investment to protect the environment. He opposed granting an exemption on the basis that the effects of current emission levels are not fully known. It was suggested that a complete study of the area be undertaken not later than the first of April, 1973, for a period of five years during which the plant should be required to operate at 98 per cent efficiency. The study should be conducted by various government departments at the expense of the applicant and should investigate:

1. The annual increase of sulphur in the soils.

2. The effect of sulphur dioxide on plant and animal life.

3. The effect of sulphur dioxide on forage and grain crops.

4. The effect of sulphur dioxide and hydrogen sulphide on the residents of the area surrounding the plant.

He also stated that the results of any monitoring or special studies conducted by Gulf should be made available to the people of the area.

Mr. D. M. McDonald stated that economic considerations should be secondary in determining required recovery levels. He requested that further environmental studies be completed before relaxation of sulphur recovery levels is permitted. He also expressed concern over the accuracy and reliability of air monitoring equipment stating that it should not be assumed that all instrument readings are correct.

Mr. L. L. Kennedy questioned air quality standards and expressed concern about the long term effects of emissions, particularly with the possibility that other plants could eventually be located in the area. He stated that the results of all monitoring and testing should be reported to the people.

Mr. G. R. Graham expressed concern about several problems he has experienced in the area. He referred to odours and black smoke in the area from gas processing operations. He stated that compressor trouble at the plant occurs frequently causing pollution problems. He stated that the adequacy of automatic well shut-in equipment should be investigated and that, in his opinion, ambient air monitoring equipment may not be effective.

Mr. Richard Gabler expressed opposition to granting an exemption from the guidelines. He stated that granting an application for exemption from the guidelines for economic reasons would not be valid and would be unfair to the citizens of the Province since all pollution controls cost money. He also stated that the Board should independently monitor stack gas emissions at the source using a continuous recording device.

Environment Canada stated that exemption of the Strachan Plant from the minimum sulphur recovery efficiency guidelines would be premature at this time as current levels of information are not adequate to assure that no adverse environmental effects will occur. It stated that further investigation of dispersion characteristics in the area under a variety of climatic conditions would be desirable. It also stated that the exposure cylinder readings submitted by Gulf indicate an increase in the sulphur budget in the area surrounding the plant and questioned the adequacy of the current monitoring program. It stated that the effects of current emission levels on the biological receptors in the surrounding area are not yet known and that special precautions are warranted in view of the size and number of gas processing plants located and proposed in this region. It stated that the best practical technology should be applied to minimize sulphur dioxide emissions in the area.

VIEWS OF THE EXAMINERS

The examiners are of the view that an application for exemption from the guidelines should have consideration for the economics of increased sulphur recovery and also for other aspects of the plant operation, such as compliance with the air quality standards and the complaint history in the area. The examiners expect that plant operations would be conducted so as to have no detrimental impact on the local environment, to satisfy Provincial Ambient Air Quality Standards and to result in a minimum number of complaints, quite apart from the requirements of the sulphur recovery efficiency guidelines. As stated in Decision 73-2, the sulphur recovery efficiency guidelines are designed to provide for a sulphur recovery level that is as high as practical having regard for both economics and sulphur recovery technology.

1.00 Overall Conditions of the Environment

The examiners have carefully considered the evidence presented by the interveners with respect to the overall conditions of the environment in the general Strachan Area and, after consultation with the Board field staff and the Department find that:

1.01 Air quality monitoring in the area to date indicates satisfactory operation with respect to Provincial Air Quality Standards, however, an intensification of monitoring is desirable and has recently been required by the Board and the Department of the Environment. The air quality monitoring system is being expanded to require five additional exposure cylinder stations and one additional continuous monitor to be operated for 12 months of each year. This increases the monitoring requirements to 25 exposure cylinder stations and two continuous monitoring stations. The examiners consider the extent of the expanded monitoring network to be satisfactory.

1.02 The air quality monitoring and other testing carried out in the area have not indicated adverse environmental effects at current emission levels.

1.03 Existing monitoring equipment provides a reasonably reliable indication of sulphur dioxide and hydrogen sulphide concentrations of the air being sampled.

1.04 Sulphur dioxide emission levels in the general area should decrease substantially at the end of 1973 when the second tail gas clean-up plant is put into operation at the Aquitaine Ricinus-West Processing Plant, increasing its recovery from 96 to 98 per cent and reducing its maximum sulphur dioxide emsiion rate from 336 long tons per day to 168 long tons per day.

1.05 Complaints respecting the plant operations have been expressed by local residents both prior to and during the hearing of the application. Many of the complaints appear to relate to operations in the area other than emissions from the incinerator stack. Some of the specific complaints and examiners comments are as follows:

(a) Flaring at the plant: Flaring has resulted primarily from periodic plant recycle compressor shut-downs. Flaring due to other causes has been minimal and infrequent. The total volume of gas flared at the plant has been low.

(b) Flaring in the field: Flaring in the field due to well testing operations resulted in complaints in the past; however, flaring in the field has now been essentially eliminated.

(c) Black smoke: Flaring has resulted in emissions of black smoke on some occasions.

(d) Odours: Sources of odours in the plant and field are generally well controlled.

(e) Shut-in of wells: Each well flowing to the plant is equipped with automatic shut-in equipment to shut-down the well in the event of high or low line pressure. This equipment is located at the well site and actuates a shut-down valve on the wellhead. Each well can also be shut-down remotely from the plant control room either through the action of the plant operator or automatically when the plant emergency shut-down system is activated or an electrical power failure occurs. In the view of the examiners this system is satisfactory.

(f) Availability of special environmental information: Making available to the public the results of any plant monitoring and special studies carried out in the area in which gas processing occurs would be desirable. The Department of the Environment requires an annual summary and evaluation report of the performance of the air and water pollution control facilities and systems. A copy of this report could be filed with the local County, Municipality or Improvement District.

1.06 With regard to the concern expressed at the hearing that pollution levels would increase if other plants are built in the area, the examiners note that all Provincial environmental standards would have to be met before additional processing facilities are approved.

1.07 It is not necessary to carry out independent Governmental continuous monitoring of incinerator stack emissions. The examiners are of the view that present periodic stack surveys and air quality monitoring studies by the Board and the Department and the regular reporting by the Operator provide adequate surveillance of plant operations.

1.08 The incinerator stack was designed to meet a calculated tree top level sulphur dioxide concentration standard of 0.30 parts per million. Calculations by Board staff confirm that this can be achieved at currently approved maximum emission levels in all directions from the plant with due regard for the topography of the area. The Board staff calculates maximum tree top level concentrations of 0.28 parts per million and maximum ground level concentrations of 0.23 parts per million. Increasing the sulphur recovery to 98 per cent would reduce the maximum sulphur dioxide emission rate from the plant from 76.4 long tons per day to 38.2 long tons per day and the calculated maximum tree top level sulphur dioxide concentration to 0.14 parts per million.

2.00 Economics of Additional Sulphur Recovery

With respect to the cost of additional sulphur recovery at the plant the examiners find as follows:

2.01 Having regard for the capacity of the Strachan Gas Plant and the quality of the feed gas going to the sulphur plant, the minimum sulphur recovery according to the guidelines should be 98 per cent.

2.02 The present sulphur recovery efficiency of 96 per cent at the Strachan Gas Plant is probably close to the maximum operating efficiency for the existing facilities. The likelihood is that a tail gas clean-up process would be required to achieve a 98 per cent recovery.

2.03 The capital and operating costs of tail gas clean-up facilities as estimated by Gulf appear realistic. The examiners also estimate the capital cost to be $2,200,000 and the annual operating cost to be $220,000 in 1975.

2.04 The cost of constructing a railway spur from Rocky Mountain House into the Gulf Strachan and Aquitaine Ricinus West gas processing plants to transport sulphur would be approximately $14,000,000. Assuming this cost was amortized over 15 years and shared by the two plants on the basis of total sulphur reserves and distance travelled from each plant, the Strachan share of the annual railway cost would be approximately $160,000.

2.05 The examiners evaluated the economics of the sulphur recovery operation and found that it would not be economic to add tail gas clean-up facilities to increase the sulphur recovery efficiency to 98 per cent. The examiner's evaluation indicated a negative rate of return on the sulphur plant facilities including installation of a tail gas clean-up process. The method of evaluation followed that outlined in Decision 73-2 and is described below:

(a) The required capital cost for a tail gas clean-up plant was taken to be $2,200,000. A carryforward of $3,400,000 was added to this to account for unrecovered sulphur plant investment as at December 31, 1974. Part of the past investment was assumed to be paid out on the basis that, even though sulphur sales from the plant may not have physically occurred, this was a result of a business decision by the operator to ship his sulphur from a less remote plant.

(b) The annual operating cost for the Claus portion of the sulphur plant was estimated as eight per cent of the total capital investment in 1971 and that amount was thereafter escalated at three per cent per year. An additional annual operating cost for the tail gas clean-up plant amounting to $220,000 was added in 1975 and escalated at three per cent per year thereafter. Allowance for reduction in operating costs due to decline in field productivity later in its life was included.

(c) A cost of $160,000 per year was added to the operating costs to provide for railway payments.

(d) The sulphur production forecast submitted by Gulf was used in the economic evaluation.

(e) The sulphur price and percentage sulphur sales forecast used is given below:

Year	percentage of production sold	netback sulphur price ($/LT)
1975	50	9.00
1976	50	10.00
1977	50	11.00
1978	52	12.00
1979	54	12.00
1980	56	12.00
1981	58	12.00
1982 and thereafter	60	12.00

The above forecast differs from that given in Decision 73-2 in iew of recent improvements in the price of sulphur.

2.06 In view of the unfavourable economics indicated by the
valuation described in section 2.05 the examiners evaluated
he economics of the sulphur recovery operation for sulphur re-
overy levels in the range 96 to 98 per cent. This further
valuation indicated a rate of return before taxes on the sulphur
lant facilities in the range of 4.0 to 10.4 per cent for a
ulphur recovery of 97.0 per cent. For the purpose of this
valuation it was assumed that either a partial tail gas clean-
p facility or a fourth Claus converter stage would be required
o achieve a 97.0 per cent recovery. The capital expenditure
equired was estimated to be in the range $850,000 to $1,400,000
nd the resultant increase in annual operating costs to be in
he range $68,000 to $140,000. Under these conditions the maxi-
um sulphur dioxide emission rate would be 57.3 long tons per
ay and the maximum calculated tree top level sulphur dioxide
oncentration would be 0.21 parts per million.

2.07 The present rate of take is substantiallly higher than
he more normal rate of one MMcfd for each 7.3 Bcf of recoverable
eserves. The Board originally estimated the initial gas in place
n the entire Strachan D-3 A Pool to be 2,415 Bcf. Based on
roduction data, the Board has recently revised its estimate of
nitial gas in place to 1,563 Bcf. (It should be noted that these
igures represent reserve estimates for the entire Strachan D-3
Pool and not just for that fraction of the pool reserves to be
rocessed by the subject plant). If the reservoir was produced
t a rate of take of one MMcfd for each 7.3 Bcf of reserves, the
nlet rate to the plant would decrease by the ratio of the above
eserve estimates, or to approximately 65 per cent of the current
ate of take. Under these conditions the maximum sulphur inlet
ate would become 620 long tons per day and the sulphur recovery
fficiency required by the guidelines, by approximate interpol-
tion, would be 96.5 per cent. Under these conditions the maximum
ulphur dioxide emission rate would be 43.4 long tons per day
nd the maximum calculated tree top level sulphur dioxide concen-
ration would be 0.20 parts per million. A sulphur recovery level
f 96.5 per cent could probably be achieved through minor modifi-
ations to the existing facilities or through installation of a
ourth catalytic conversion stage to the existing sulphur plant.

2.08 Processing at the plant of sour gas in addition to that
roduced from the Strachan D-3 A Pool would increase the life of
he plant, and could make economic the sulphur recovery facilities
ncluding addition of tail gas clean-up facilities.

2.09 A five-year test at the 98 per cent recovery level as
equested by an intervener would be equivalent to denying the
pplication. It would not be practical to install equipment for
short period of time to carry out such a test as any additional
ulphur recovery facilities would be essentially permanent.

DISCUSSION AND RECOMMENDATIONS

1. The Board has indicated that its major consideration in establishing a sulphur recovery requirement level will be the overall economics of the sulphur plant operation since it expects all environmental requirements to be satisfied regardless of the sulphur recovery efficiency. Having this in mind, the examiners' evaluation of the sulphur plant economics at the forecast sulphur production rate indicated that a recovery of 98 per cent should not be required. The evaluations carried out at intermediate sulphur recovery levels indicate that the sulphur recovery could be increased to 97 per cent without causing the sulphur recovery operation to be uneconomic.

The examiners therefore recommend that the application be granted in part such that the sulphur recovery efficiency required be increased to 97 per cent to apply after December 31, 1974. Gulf would be required, in accordance with Informational Letter No. IL 71-29, to apply prior to May 31, 1973, for approval of the proposed modifications necessary to meet this requirement. It is recommended that Gulf also be required at that time to describe the manner in which the maximum calculated concentration of sulphur dioxide at tree top level would be maintained below 0.20 parts per million.

2. In view of the fact that the examiners' evaluation of the plant economics was based on the sulphur production forecast submitted by Gulf, the examiners recommend that this decision be reviewed if significant additional sour gas reserves are committed to the plant. An additional sour gas reserve containing in the order of three million long tons of sulphur might be sufficent to justify requiring a 98 per cent sulphur recovery efficiency.

3. With respect to other environmental matters in the general Strachan Area, the examiners believe that further major modifications to the plant and field facilities are not warranted at this time. However, the examiners recommend that Gulf be required to undertake a plant emission study and report its findings to the Board by January 31, 1974. This study should present a detailed evaluation of:

(a) all sources of gas flaring at the plant, flared volumes from each source during 1973, flaring frequency from each source during 1973, and a description of any action taken or proposed to minimize flaring occurrences,

(b) all occurrences of black smoke during 1973, the effectiveness of the smokeless flaring facilities in controlling smoke emissions and a description of any action taken or proposed to eliminate smoke occurrences, and

(c) all sources of emissions from the plant, however minor, other than those from the emergency flare stacks and the incinerator stack, which could cause odours in the vicinity of the plant, and a description of the action proposed to eliminate these emissions.

4. The examiners recommend that the Board report its find-
ngs respecting the report required in Recommendation 3 to the
nterveners at the subject hearing after it has been reviewed
y Board staff.

5. The examiners recommend that gas processing plant
perators be required to file a copy of the annual environmental
mpact report required by the Department of the Environment with
he local County, Municipality or Improvement District Office.

IEWS OF THE BOARD

The Board agrees with the recommendations of the
xaminers.

ECISION

The Board has adopted the recommendations of the
xaminers respecting the sulphur recovery efficiency and over-
ll conditions of the environment.

In regard to the sulphur recovery efficiency the Board
equires that it be increased to 97 per cent to apply after
ecember 31, 1974. However, in the event that Gulf should wish
o reduce the approved maximum throughput at the plant, the
oard would consider an application for a different sulphur
ecovery as long as the recovery would meet the requirements of
he guidelines at the new throughput rate.

Amendment of Approval No. 1349 is being issued con-
urrently with this decision.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier, P. Eng.
Chairman

ated at Calgary, Alberta
May 4, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 73 - 10
Application No. 6407

EXEMPTION FROM SULPHUR RECOVERY GUIDELINES KAYBOB SOUTH BEAVERHILL LAKE GAS UNIT NO. 3

INTRODUCTION

Chevron Standard Limited, operator of Kaybob South Beaverhill Lake Gas Unit No. 3, applied to the Energy Resources Conservation Board for exemption of the subject gas processing plant from the sulphur recovery efficiency guidelines prescribed in Board Informational Letter No. IL 71-29. The Kaybob Gas Plant is currently permitted to process a maximum sulphur inlet of 3,570 long tons per day and required, under Approval No. 1395, to recover as elemental sulphur a minimum of 96.6 per cent of the sulphur contained in the gas delivered to the plant. Informational Letter No. IL 71-29 requires that a plant having a sulphur inlet rate of over 1,000 long tons per day and processing a favourable quality acid gas, recover 98 to 99 per cent of the sulphur delivered to the plant. The guidelines indicate that a recovery of 99 per cent would be required for the Kaybob Plant.

On March 27, 1973 the Board published notice of the application. The notice stated that, unless objection was filed on or before April 19, 1973, the Board might grant the application in part by setting the sulphur recovery efficiency to apply after December 31, 1974 at 98 per cent. No objection to the notice was received. The Board therefore decided not to hear the application and to prepare this report to document the Board's decision respecting the application.

THE APPLICATION

Chevron requested exemption from the guidelines stating that:

1. The plant was built in good faith, under a higher design efficiency than any similar plant approved to that time, in order to meet the then anticipated maximum sulphur recovery efficiency requirements in an atmosphere of increasingly strigent regulation of resource conservation and environment protection.

2. The economic impact of the higher efficiency requirements of the guidelines is severe.

3. The Kaybob South Beaverhill Lake Gas Unit No. 3 gas plant has a finite life and will not continue its design emission level indefinitely.

4. Maintenance of ambient air quality standards should be the controlling factor in gas plant operations and not gas plant efficiencies.

Chevron submitted the results of performance testing carried out at the plant to evaluate the recovery capability of the existing four-stage modified Claus sulphur recovery facilities. The report indicated that, at the time of the evaluation, Train 1 was operating at 97.5 per cent recovery efficiency and Train 2 was operating at 98.2 per cent recovery efficiency for an average of 97.8 per cent, compared to the recovery required by Approval No. 1395 of 96.6 per cent. The report concluded that with replacement of deactivated catalyst in Train 1 and with minor modifications to plant equipment and operating conditions, it would be possible to achieve a recovery efficiency of 98 per cent for extended periods.

In regard to the economic impact of higher efficiency requirements Chevron submitted a cost study of various means of achieving sulphur recovery efficiencies in the 98 to 99 per cent range. For the purposes of the economic study it evaluated three cases for which the following assumptions were made:

1. For case 1, that by changing catalyst on a five-year cycle the recovery efficiency of the existing plant would vary from 98.6 per cent with new catalyst to 97 per cent after five years and would yield an average of 97.8 per cent.

2. For case 2, that by changing the catalyst on a two-year cycle the recovery of the existing plant would vary from 98.6 per cent with new catalyst to 98 per cent after two years and would yield an average of 98.3 per cent.

3. For case 3, that by operating the existing four-stage plant in accordance with case 2 and adding a tail gas clean-up facility, an average recovery of 99 per cent could be maintained.

Chevron assumed a decline in sulphur sales volumes to seven per cent of production in 1985 and assumed plant net-back sulphur prices in the range 0.13 to 4.37 dollars per long ton. For the case 3 evaluation Chevron assumed a tail gas clean-up plant investment of $5,800,000 would be required in 1974 and that annual operating costs would be increased by some $800,000 commencing in 1975.

Chevron's evaluation of the sulphur plant cash flow for the period 1969 to 2000 indicated that the sulphur plant investment would not be recovered for any of the cases studied. Chevron calculated an undiscounted net loss on the sulphur plant operation of $28,558,000 for case 1, $30,455,000 for case 2 and $42,934,000 for case 3. Chevron concluded that required higher sulphur recoveries would be increasingly costly and could not be justified on economic grounds.

As part of its economic evaluation Chevron submitted a production forecast indicating the decline in production and emissions expected to commence early in the life of the scheme. The plant is an integral part of a gas cycling project and hence its sulphur production is expected to commence decline upon sweet gas breakthrough which is anticipated in 1977. This decline will continue through the life of the cycling and blowdown phases of the project.

In support of its argument that maintenance of ambient air quality standards should be the controlling factor in gas plant operations Chevron referred to the results of exposure cylinder monitoring, continuous ambient air quality monitoring and other environmental studies undertaken in the plant vicinity. Chevron stated that its monitoring experience to date indicates that, except for minor periods of upset, the plant is capable of continuously meeting the Alberta ambient air quality standards and that monitoring indicates no justification for requiring higher sulphur recoveries at the plant.

VIEWS OF THE BOARD

As stated in previous decisions concerning similar applications the Board believes that, even though by present standards the environmental aspects of a plant operation might be satisfactory, maximum practical sulphur recovery should be achieved both in the interests of conservation of a natural resource and to minimize sulphur dioxide emissions with regard to the potential for adverse environmental effects on a broad scale. The Board stated that, in general, the sulphur recovery specified in the guidelines should apply providing that it would give before income tax a discounted rate of return in the range of seven to ten per cent on the total undepreciated investment attributed to the total sulphur recovery facilities evaluated as at January 1, 1975.

The Board has assessed the economics of the operation of the sulphur recovery facility at the subject plant to determine the discounted rate of return after 1974 for various sulphur recovery levels in the range 98 to 99 per cent. The Board calculated that approximately $13,900,000 of past sulphur plant investment should be carried forward to January 1, 1975 as unrecovered investment for the existing facility. The Board also included in its evaluation an annual railway payment of

$423,000 to cover the cost of the rail spur to the plant and assumed the sulphur prices and sulphur sales fractions given below.

Year	percentage of production sold	netback sulphur price ($/LT)
1975	50	9.00
1976	50	10.00
1977	50	11.00
1978	52	12.00
1979	54	12.00
1980	56	12.00
1981	58	12.00
1982 and thereafter	60	12.00

The Board first evaluated the economics of achieving 98 per cent recovery with the existing four-stage Claus process alone using the data presented earlier in this report and Chevron's sulphur production and operating cost estimates for case 2. This evaluation indicated a discounted rate of return before taxes on the sulphur plant facilities for the period 1975 to 2000 of 12.7 per cent.

The Board carried out a further evaluation of the economics of achieving 98.5 per cent recovery. It assumed that a tail gas clean-up process would be required and that the necessary capital and annual operating costs would be $4,600,000 and $690,000 respectively. Using these costs and the data described for the 98 per cent case above this evaluation indicated no payout for the period 1975 to 2000.

A similar evaluation of the economics of achieving 99 per cent recovery for the period 1975 to 2000 indicated no payout for the period 1975 to 2000.

Based on its evaluations the Board is of the view that the application should be granted, in part, and that the recovery required after December 31, 1974 be set at 98 per cent, based on the following findings:

1. The application indicates that a recovery of 98 per cent, within the recovery range required by the guidelines, can be achieved with minor modifications to the existing facilities and at a relatively small extra expense (less than $2,000,000 over the life of the scheme).

2. The Board's economic evaluation shows that the cost of achieving 98.5 to 99 per cent recovery is excessive and the additional investment is not warranted under the Board's policy.

3. The plant is remote, no adverse environmental effects have been observed to date and sulphur production will commence to decline in 1977, due to sweet gas breakthrough,

to approximately 25 per cent of present rates by 1985.

4. No objections to the notice of the application were received.

DECISION

The Board grants, in part, the application by Chevron for exemption of the Kaybob Gas Processing Plant from the sulphur recovery efficiency guidelines set out in Board Informational Letter No. IL 71-29. The Board requires that the plant meet a sulphur recovery requirement of 98 per cent by December 31, 1974. Amendment of Approval No. 1395 is being issued concurrently with this decision.

ENERGY RESOURCES CONSERVATION BOARD

GWGovier

G. W. Govier
Chairman

Dated at Calgary, Alberta
June 25, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-11
Application No. 7085

PRODUCTION OF GAS - HOUSE MOUNTAIN AREA

1. INTRODUCTION

Chevron Standard Limited (hereinafter referred to as "Chevron") applied under section 38 of The Oil and Gas Conservation Act for an order approving a scheme for the production of gas from the Grosmont Formation in Township 82, Ranges 15, 16 and the East half of 17, West of the 4th Meridian and Township 83, Ranges 15 and 16, West of the 4th Meridian. The Grosmont and overlying McMurray Formations in the foregoing area (hereinafter referred to as the "House River Area") contain gas and crude bitumen which may be within or immediately adjoining oil sands. Chevron drilled five wells in the House River Area, and wells located in Legal Subdivision 11, Section 19, Township 82, Range 15, West of the 4th Meridian and Legal Subdivision 6, Section 34, Township 82, Range 16, West of the 4th Meridian have been completed as Grosmont gas wells. If approval is granted Chevron intends to drill more wells to delineate the gas reserve and determine whether commercial development of it is feasible.

The Board reviewed the application and subsequently met with the applicant to discuss the issues outlined below. In view of the confidential status of much of the relevant data the Board decided not to hold a public hearing with respect to the application, but decided to inform industry of its decision by issuing this decision.

1.1 Definition of Issues

The principal issues involved in the application appear to the Board to concern

(a) geology and reservoir communication in the McMurray and Grosmont Formations,

(b) reserves of gas and crude bitumen,

(c) possible detrimental effect of gas production prior to the recovery of crude bitumen, and

(d) gas supply for crude bitumen recovery.

2. GEOLOGY AND RESERVOIR COMMUNICATION OF THE McMURRAY AND GROSMONT FORMATIONS

2.1 Views of Chevron

Chevron stated that the structurally high subsurface feature in the House River Area consists of an erosional remnant of the up-dip subcropping edge of the Devonian Grosmont reef complex which extends in a northerly direction from the Craigend Field into the House River Area. Chevron submitted isopach and structural maps and cross-sections to show the location and areal extent of the Grosmont feature in the House River Area and its relationship to the overlying McMurray Formation. Chevron stated the Grosmont in the House River Area consists of limestone with intercrystalline porosity ranging in values from 3 to 5 per cent and permeabilities generally less than 1.0 millidarcies on uncleaned core, and porosity values of from 5 to 20 per cent and permeabilities to 10 millidarcies for core cleaned in toluene. The McMurray Formation consists of sand lenses averaging less than 10 feet in thickness which are interbedded with silty shales. The McMurray Formation thins as it laps over the Grosmont feature and is almost all shale on the crest of the area.

Chevron did not specifically state that there was reservoir communication between the Grosmont and McMurray Formations, but at the meeting it did not oppose the view that such communication was possible. Chevron contended that if reservoir communication exists it would be very poor because of the poor permeability in the Grosmont reservoir, the relatively restricted contact that the thin sand lenses would make on the Grosmont feature, the shaly nature of the McMurray Formation in the crest area and the low reservoir transmissibility of reservoirs containing crude bitumen.

2.2 Views of the Board

The Board agrees with the geological interpretation submitted by Chevron. The Board believes that the Grosmont and McMurray Formations are in reservoir communication and concurs with Chevron that communication is likely to be of a restricted nature.

3. RESERVES OF GAS AND CRUDE BITUMEN

3.1 Views of Chevron

Gas was recovered on drill stem test in commercial quantities from the Grosmont Formation in the wells, CHEVRON CDN

SUP HOUSE R 11-19-82-15, and CHEVRON CDN SUP HOUSE R 6-34-82-16, which are completed as gas wells. Employing reservoir factors estimated from core analyses, Chevron estimated the potential in place gas reserves for the House River Area to range from 62 to 215 billion cubic feet. The higher estimate is based on an assumption that the porosity improves in the area to the east of the well located in Legal Subdivision 6 of Section 34.

Gas was recovered from the McMurray Formation at rates of 168 and 465 thousand cubic feet per day in the wells in Legal Subdivision 6 of Section 34 and Legal Subdivision 11 of Section 19, respectively. Chevron did not estimate reserves for the McMurray Formation because it did not consider them to be of significant commercial value.

At the meeting, the Board raised the matter of the possibility of recoverable crude bitumen in the Grosmont Formation, and Chevron subsequently submitted core analyses from the House River Area wells that indicated a high residual crude bitumen saturation in the Grosmont Formation. Chevron stated that visual examination of core samples confirmed the low porosity and permeability values shown on the core analyses. Chevron contended that the crude bitumen in the Grosmont Formation in the House River Area is not recoverable because of the very poor reservoir characteristics.

In order to establish the distribution of crude bitumen saturation in the McMurray Formation, Chevron cored the McMurray Formation in the well, CHEVRON BP GRAND RAPIDS 11-25-83-17 W4 and CHEVRON CDN SUP HOUSE R 11-19-82-15 W4 well. In the Grand Rapids well, there was 19.5 feet of sand containing greater than 6 per cent bitumen by weight in six separate sands of which the thickest sand was 6.5 feet. The well in Legal Subdivision 11 of Section 19 did not encounter sand with greater than 6 per cent bitumen by weight and only 2.1 feet of sand had greater than 4 per cent bitumen by weight. The net isopach map of sand thickness having greater than 6 per cent bitumen by weight, submitted by Chevron, indicated no oil sand on the crest of the Grosmont high.

Chevron concluded that the crude bitumen in the area is not recoverable due to the thinness of the sands, their discontinuity from well to well and the likelihood that much more than 6 per cent crude bitumen by weight would be required for an in situ recovery process, the only type of recovery feasible at the depth of burial of bitumen in this area.

3.2 Views of the Board

The Board agrees with Chevron that the gas discovered in the Grosmont Formation indicates a commercial gas pool that has not been fully delineated as yet. The Board also concurs that the gas in the McMurray Formation is not a commercial reserve. It is not uncommon to find localized accumulations of gas in association with the bituminous sands and the Board believes this to be the case in the House River Area.

The Board believes that the crude bitumen found in the Grosmont is not likely to be of commercial value due to the low porosity and permeability of the reservoir. Further, the Board concludes that the crude bitumen in the McMurray Formation in the House River Area should not be classed as recoverable under current or foreseeable technology, for the reasons advanced by the applicant.

4. POSSIBLE DETRIMENTAL EFFECT OF GAS PRODUCTION PRIOR TO THE RECOVERY OF CRUDE BITUMEN

4.1 Views of Chevron

Chevron stated that since the crude bitumen is not recoverable, there would be no detrimental effect from producing gas. Chevron also commented that, by producing the gas, the reservoir properties may be improved by the creation by the flowing gas of a flow path for materials that might be injected if recovery of the bitumen were undertaken.

4.2 Views of the Board

The Board believes that since the crude bitumen in the immediate vicinity of the Grosmont gas discovery can not be considered recoverable under current and foreseeable technology there could be no detrimental effect of gas production at this time.

5. GAS SUPPLY FOR CRUDE BITUMEN RECOVERY

5.1 Views of Chevron

Chevron stated that it did not consider it necessary to conserve the House River Area gas reserves for the recovery of crude bitumen in the general area because the pipe line system that would remove the gas could provide the necessary facilities to carry gas into the area when and if it were required.

5.2 Views of the Board

The Board agrees that gas could be made available, by way of existing gas pipe line systems, to any crude bitumen recovery project in the general area that might require gas. Also, the Board anticipates that in the future, crude bitumen recovery schemes will tend to become self-sufficient from an energy viewpoint.

6. DISPOSITION OF APPLICATION

The Board grants the application of Chevron for approval of a scheme for the production of gas from the Grosmont Formation in the lands set out in the application. The application is granted by Approval No. 1901, being issued concurrently with this report.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
June 28, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-12
Applications No. 6813 and 6814

OPERATION IN ACCORDANCE WITH GOOD PRODUCTION PRACTICE AND CONCURRENT PRODUCTION ROWLEY PEKISKO A POOL

1.0 THE APPLICATION AND HEARING

Blake Mineral Resources Ltd. applied with respect to the Rowley Pekisko A Pool

(a) by Application No. 6813, for permission to produce the oil accumulation in accordance with good production practice, and

(b) by Application No. 6814, for an amendment to Board Approval No. 883 to require the termination of gas production from the well, AMERADA HONOLULU ROWLEY 2-16-32-20, and to permit the delivery of solution gas from the pool to the Ghost Pine Unit or injection of it into the said well.

The applications were heard on March 14, 1973 by examiners N. A. Macleod, Q.C., R. G. Evans, P. Eng. and R. W. Edgecombe, P. Eng.

2.0 APPEARANCES

The following appeared at the hearing:

	Represented by:	Abbreviation Used in Report
Blake Mineral Resources Ltd.	D. J. B. Marshall, P. Eng. N. S. Marshall, P. Eng. G. R. A. Alderman, P. Geol.	Blake
Gulf Oil Canada Limited	G. C. Hos, P. Eng. W. K. Good, P. Geol. R. B. Thomas, P. Geol.	Gulf
Energy Resources Conservation Board	G. R. Heming, P. Eng. H. J. W. Piét, C.E.T. C. A. Wiltzen, P. Geol. L. A. Samson	Board Staff

3.0 BACKGROUND AND SUBMISSIONS

The Rowley Pekisko A Pool was discovered in 1960. Because the production from this pool exhibited a relatively high gas-oil ratio, Amerada roleum Corporation, in 1966, obtained permission to gather solution gas and nject it into the gas well, AMERADA HONOLULU ROWLEY 2-16-32-20, under roval No. 883.

In 1967 Amerada Petroleum Corporation applied to the Board for roval of a scheme for concurrent production of oil and gas, relief from -oil ratio penalties and permission to produce crude oil in accordance h good production practice. The Board approved concurrent production ler Approval No. 1094 and stipulated that gas-oil ratio penalties against oil allowables in the pool should be based on Table A-600 using net gas duction, being the difference between produced gas and that injected or ivered for sale. The request for GPP was denied.

Blake became unit operator of the Rowley Pekisko Unit No. 1 fective January 1, 1973 and subsequently applied for amendment of Approvals . 883 and No. 1094 to change the name of the holder of these approvals, and ereby undertook to carry out the schemes of concurrent production and the riodic gas injection. Blake's application was granted and Approval No. 883 s amended and reissued as Approval No. 1836, and Approval No. 1094 was ended and reissued as Approval No. 1837.

Technical studies relating to and submitted in support of the subject plications are:

(a) Letter report re: Geological study of the Rowley Field prepared by C. Sproule and Associates Ltd. (hereinafter called the Sproule Report).

(b) Reservoir study re: Rowley Pekisko A Pool prepared by N. S. Marshall d D. J. B. Marshall (hereinafter called the reservoir study).

The Sproule Report was prepared for Blake to determine if further illing in the Rowley Pekisko A Pool is feasible and to determine if geologi- l communication exists between the gas cap and the oil accumulation.

The reservoir study was made to determine if effective pressure mmunication exists between the oil and gas bearing parts of the pool and, if , if continued production of the gas cap would adversely affect the recovery oil.

Gulf intervened in opposition to the proposed cessation of gas cap oduction from the 2-16 well (Application No. 6814). It intervened for the rpose of cross-examination with respect to Application No. 6813 for GPP.

) DEFINITION OF THE ISSUES

Production of a gas cap concurrently with its associated oil accumula- on may affect oil recovery depending on the relative rates of depletion and e freedom of pressure and fluid communication between the oil and gas parts the pool. The extent of communication that exists can be judged from geologi- l evidence, pressure data and production characteristics. Approval of con- rrent production may also depend on the relative sizes of the gas and oil cumulations and their economic values. Also at issue is the right of Blake determine the disposition of the gas which is within the Ghost Pine Unit. e issues are:

(a) the geological nature of the reservoir,

(b) evidence of pressure communication,

(c) the determination of oil and gas reserves,

(d) effects of continued gas production on the oil recovery,

(e) effects of discontinuing the gas production on the recovery of pools in the Ghost Pine Unit and on the operations of the Ghost Pine Gas Plant,

(f) responsibility for operations, and

(g) the need for good production practice.

5.0 GEOLOGICAL NATURE OF THE RESERVOIR

5.1 Views of Blake

Blake claimed that the Pekisko Formation in the Rowley Field consists of two stratigraphically definable units, referred to as the Upper Pekisko and Lower Pekisko, which constitute a single reservoir. The presence of a reasonably uniform gas-oil contact at -1713 feet subsea was presented as the main evidence in support of communication. Fracturing within the reservoir was mentioned as a further indication that communication exists within the reservoir.

Blake described the porosity within the Pekisko as consisting of numerous porous stringers that are in communication within the gross section. It submitted that unless an attempt was made to map the porosity as it occurs within stratigraphically identifiable subzones, the porosity trends as shown on the maps included in Exhibit I would be obscured.

Blake concluded, based on the evidence cited, that the Rowley Pekisko A Pool is a continuous reservoir and that the gas accumulation in the 2-16-32-20 well is in communication with the oil in adjacent wells.

5.2 Views of Gulf

Gulf stated that there is general agreement between itself and the applicant on the major elements of Mississippian stratigraphy in the Rowley area. It claimed, however, that there is limited direct evidence, such as drill stem tests, of the presence and elevation of a uniform gas-oil contact and that, if present, such an interface may indicate effective communication only in terms of geological time and not in terms of the producing life of the field. Gulf stated that the Rowley Pekisko reservoir is characterized by porous bands interspersed with dense bands, and that this suggests poor reservoir communication, especially in the vertical direction. Gulf also interpreted the separation between the completion interval in the 2-16-32-20 gas well and that in the adjacent oil wells, as consisting of a substantial thickness of dense beds, determined by applying cut-offs of 3.0 per cent porosity and 1.0 millidarcies permeability. Pressure data were also cited as evidence to support the presence of an effective barrier to communication.

Gulf concluded that the weight of geological evidence available sup- rted the interpretation that the oil and gas accumulations in the Rowley kisko reservoir are entirely separate or have very limited interconnection.

5.3 Views of the Examiners

It is evident from a study of logs and core analysis data that rigid rrelations cannot be carried across the entire area of the Rowley Field. rosity development within the Pekisko is random and consists of numerous rous stringers which cannot be correlated from well to well. Similarly, the nse bands do not correlate. The stratigraphic marker horizon which separates at is defined by Blake and Gulf as Upper and Lower Pekisko is present in most lls. This marker consists of a slightly argillaceous fractured carbonate at does not in itself constitute an effective barrier.

In most cases, the Upper Pekisko is gas bearing, while the Lower kisko is oil bearing, but the presence of oil in the Upper Pekisko in the -9-32-20 well and gas in the Lower Pekisko in the 10-9-32-20 well, as indicated om drill stem tests, would seem to be evidence in support of reservoir commun- ation.

The definition of so-called "dense" or tight segments by means of rosity and permeability cut-offs is fundamental to the issue of reservoir mmunication as well as the interpretation of reserves. The cut-offs applied the Board staff in its determination of net pays, 2 per cent and 0.1 milli- arcies, were somewhat lower than the 4.5 per cent and 0.7 millidarcies applied the applicant and the 3 per cent and 1.0 millidarcies used by the intervener, it based on experience from similar Pekisko pools in other fields such as ining and Twining North the Board staff's cut-offs appear to be most appropri- te.

Reservoirs of this type contain relatively thick sections of rock ith porosities in the range of 2 to 4 per cent and permeabilities of 0.1 to .0 millidarcies that apparently do not inhibit the flow of fluids. The aminers agree that the presence of fractures, which show up well in the cored lls, supports the interpretation that communication exists between sections good porosity development.

.0 THE DETERMINATION OF GAS AND OIL RESERVES IN PLACE

6.1 Views of Blake

Blake used net pay maps prepared by J. C. Sproule and Associates of e Upper and Lower Pekisko gas accumulations to estimate the gas in place at .8 Bcf. It did not submit a material balance estimate of gas in place.

In the reservoir study, Blake submitted that planimetering of the sopach maps of the Pekisko Pool presented in the Sproule Report resulted in estimate for the oil in place reserves of some 67.9 MMSTB. However, the plicant claimed that a considerable fraction of this amount should be viewed "probable" reserves rather than "proved" reserves, and that further drilling ould be required to confirm this estimate.

Blake indicated that a summation of the oil in place per drilling spacing unit, assuming uniform pay thickness equal to that at the well bore within each spacing unit, would provide a more realistic estimate of the proved recoverable reserves. Pay thicknesses were determined from logs employing cut-offs of 4.5 per cent and 0.7 millidarcies. The oil in place thus determined amounted to 16,060 MSTB. Assuming 10 per cent recovery, Blake calculated 1,606 MSTB of initial recoverable oil or 1,160 MSTB of remaining reserves.

6.2 Views of Gulf

Gulf constructed a plot of P/Z versus cumulative raw gas production for the well in 2-16-32-20, from which it estimated the original gas in place to be 50 Bcf.

Gulf stated that the oil reserves should not be based on isopach maps which extended pay thicknesses into areas beyond well control. It indicated that a better approach would be to assign reserves based on an arbitrary acreage assignment but expressed doubt about the validity of this due to variation in porosity throughout the pool. It claimed that a production decline rate of 7 per cent per year is representative and this would result in an estimate for initial recoverable oil reserves of 1,070 MSTB.

6.3 Views of the Examiners

The examiners believe that the applied cut-offs by Blake are unduly severe and that they should be about 2 per cent and 0.1 millidarcies, for reasons given in paragraph 5.3.

The Board staff volumetric estimate of gas in place of 53 Bcf is in reasonable agreement with its material balance estimate. The examiners note that the gas in place estimated by material balance ranged from 48 Bcf to 50 Bcf depending upon the positioning of the decline curve. The examiners, having regard for the volumetric and material balance estimates, believe the most reasonable estimate for the original gas in place is 50 Bcf.

The examiners do not agree with Gulf that the recoverable reserves of oil can be accurately determined in this case based on an assumed average decline.

The Board staff has re-evaluated the crude oil reserves of the pool, taking into account all data currently available including the most recent production and pressure information. The re-evaluation encompassed five different methods of reserves evaluation including a material balance approach, an extrapolation of the pool production rate decline curve, a volumetric calculation relating to drilled and productive drilling spacing units (DSUs) only, a volumetric calculation using an isopach map drawn on the basis of existing well information, and finally a volumetric "building block" approach which recognized reserves not only in drilled DSUs but also in some adjacent tracts.

The examiners have reviewed the results of the five calculations mentioned above, as well as the information supplied by Blake and Gulf. The miners agree with Blake that reliable oil reserves knowledge cannot be tained by the material balance method for the Rowley Pekisko A Pool at this me because of the small amount of cumulative production relative to the arent oil in place, the poor definition of the nature of the fluids in the ol, the lack of knowledge of the drive mechanisms, the fairly poor permeability (transmissibility) to fluids and the shortage and unrealiability of ssure measurements. Also, contrary to the view expressed by Gulf, the miners do not believe that a reliable reserves estimate is now possible by rapolation of decline curves of production rate versus cumulative production. is view is based on much the same reasons just mentioned.

The volumetric method which assigns reserves based on only those SUs which have been drilled and produced is, in the examiners' opinion, too estrictive. There does appear to be good evidence that oil exists in other SUs. However, because the pool's drainage characteristics are not yet learly defined, it would be premature to recognize as drainable reserves all he oil in place which might be interpreted to exist using the isopach map pproach even though it was based on good geological judgement.

The "building block" method thus appears, in this case and at this ime, to represent the best combination of features, allowing some recognition f the good probability that oil exists beyond the drilled tracts and yet ecognizing as drainable (or partially drainable) only those additional DSUs hich are in close association with wells. The method used was to apply the roduction Spacing Unit (PSU) validation rules including straight line validation, geological validation, distance limitations and productive well efinitions (but not the common ownership requirements) to determine which ndrilled DSUs were to be "recognized". The oil zone net pay thickness was stimated for each of these DSUs by averaging the net pay thicknesses of the djacent wells. In all cases cut-offs of 2 per cent porosity and 0.1 mullidarcies permeability were used.

In estimating a recovery factor for the "recognized" oil in place he examiners place considerable weight upon the relatively poor reservoir haracteristics as discussed in section 5.3 of this report on the geological ature of the reservoir. The recovery factor previously assigned to the pool, per cent, was determined recognizing the low level of permeability and xistence of dense segments within the gross Pekisko section. In view of the act that some in place oil reserves located at even greater distances from a ell are now being recognized, there appears to be no reason at this time to ncrease the assigned recovery factor. In addition, the existing wells have, n the past 12 years, recovered less than 1 per cent of the 55,100 MSTB oil in lace and present production characteristics average about 10 barrels of oil er day at a gas-oil ratio of some 2,000 cubic feet per barrel. In the xaminers' opinion these figures justify continuation of the 3 per cent recovery actor. The proved initial recoverable crude oil reserves are thus 1,650 MSTB.

.0 EVIDENCE OF PRESSURE COMMUNICATION

7.1 Views of Blake

Blake felt that most of the pressure information on the pool was nreliable because of insufficient shut in times. However, pressure data were aken regularly on the 10-11-32-20 shut in gas well and these data were felt to be representative. A plot of these data was presented which indicated a relatively low rate of pressure decline, approximately 1.5 psi per year, from 1960 to 1967. This decline was interpreted to be due to communication with the producing oil accumulation. In 1967 the 2-10-32-20 gas well was placed on production and the rate of pressure decline increased to approximately 4.5 psi per year. Blake said that this indicated communication between the 2-16 gas well and the 10-11 shut in gas well and also with the oil accumulation. Blake contended that the performance of the 10-11 well was indicative of the general pressure trends but was probably grossly understated because of the two mile distance between the 2-16 well and the 10-11 well.

Blake also presented an analysis of a pressure build up on the 4-16-32-20 well in which a difference of 315 psi in the built up pressure by Horner plot could be obtained. The analysis pointed out the magnitude of the possible error in a Horner extrapolation when there are only 3 points, insufficient build up times and small errors in bomb setting depths.

7.2 Views of Gulf

Gulf presented a plot of all wells in the Rowley Pekisko A Pool for which pressure data were available. A second plot was prepared using pressures which had been extrapolated to stabilized conditions. Neither of these plots showed any significant increase in the rate of pressure decline after the 2-16 well commenced production in 1967. From this pressure performance, Gulf concluded that the 2-16 well was not in communication with any of the other wells. The small pressure decline in the 10-11 well was suggestive of communication with one or more of the producing oil wells but, in that it did not reflect the major pressure decline of the 2-16 well, a reservoir discontinuity between the 2-16 well and the 10-11 well was indicated.

7.3 Views of the Examiners

The examiners reviewed all of the available pressure data on the pool. The only well in the pool which has showed a marked decline since 1967 is the 4-16 well. However, the possibility of this decline being caused by the 2-16 well's production is remote, as the pressures for the 4-16 well have been consistently 150 to 200 psi lower than those of the 2-16 well (i.e. the pressure gradient is in the opposite direction).

The examiners also reviewed the pressure data on the 10-11 well. Communication appears to be slight or non-existent. At the current rate of pressure decline in the well of 4.5 psi per year the total pressure drop would only amount to some 50 to 100 psi over the anticipated remaining oil producing life of the pool.

8.0 EFFECTS OF CONTINUED GAS PRODUCTION ON THE OIL RECOVERY

8.1 Views of Blake

Blake made estimates of the loss in oil recovery which would result from continued gas cap production using three different assumptions of the pressure decrease which would occur. The first case assumed gas cap production for 14 years at which time an abandonment pressure of 200 psi gauge would have been reached. Oil production was estimated to decline at 3 per cent per year for 9 years and thereafter at 10 per cent per year. This case resulted in the recovery of 580 MSTB or 6.5 per cent of the oil in place.

The second case also assumed gas cap production but the oil production rate was unrestricted and declined at 10 per cent per year. Recovery was estimated to be 760 MSTB or 7.5 per cent of the oil in place.

The third case assumed no gas cap production. Oil production was at capacity and declining at 7 per cent per year. Recovery was estimated to be 1,100 MSTB or 9.6 per cent recovery.

Thus a loss of 520 MSTB was postulated if the current method of operation was allowed to continue, and this loss could be reduced to 340 MSTB if GPP was granted for the oil wells but gas cap production was continued.

8.2 Views of Gulf

Gulf said that the gas cap and the oil accumulation are either entirely separate or have very limited interconnection, and so it did not submit an estimate of the amount of oil loss which would occur as a result of continued gas cap production.

8.3 Views of the Examiners

The examiners are of the opinion that with the unreliable pool data it is not possible to determine with confidence whether migration of oil into the gas cap will occur. The available pressure data are subject to widely varying interpretations but, as discussed in Section 7.3, suggest little or no reservoir pressure communication between the oil bearing part of the pool and the gas cap.

The cases presented by Blake are predicated upon the assumption that good pressure communication exists within the pool and for this reason do not, in the examiners' view, properly represent the effect on oil recovery of either concurrent gas cap and oil production or accelerated oil production rates. The Blake cases also contain changing assumptions as to the rate of oil productivity decline which strongly influence the calculated results but which are not supported by field evidence. The examiners believe that immediate steps should be taken by the operators in the pool to obtain more reliable pressure data so that a better understanding of the reservoir behaviour may be obtained and so the optimum method of depletion for the pool may be determined with confidence.

Examiner N. A. Macleod believes that if concurrent production is to be continued, it should be shown that gas production would have so little effect on the oil production as to warrant its continuation while oil is being produced.

Examiners R. G. Evans and R. W. Edgecombe believe that since approval to produce the oil and gas concurrently has been in effect since 1967, it is necessary to determine if the gas production is having sufficient effect upon the oil production to warrant shutting in of the gas cap in the interest of conservation. The examiners believe, however, that an error was made when Approval No. 1837 (originally Approval No. 1094) was assigned to Blake. The examiners are of the opinion, in pools where the ownership of the oil differs from that of the gas, that if concurrent production of the oil and gas is considered desirable, the approval to produce concurrently should be held by the owner of the gas rights. Since the Ghost Pine Unit has not requested such an approval, the examiners believe that Approval No. 1837 should be rescinded.

9.0 EFFECTS OF THE CESSATION OF GAS PRODUCTION ON THE GHOST PINE PLANT

9.1 Views of Blake

Blake submitted that the gas reserves of the Rowley Pekisko A Pool are 6.36 per cent of the total reserves which are contributory to the Ghost Pine Plant but 11 per cent of the plant intake is from Rowley, and hence this reservoir is being depleted faster than other pools producing into that plant.

9.2 Views of Gulf

Gas cap gas and solution gas from the Rowley Pekisko A Pool are unitized within the Ghost Pine Unit. Gulf as operator of the Ghost Pine Unit, pointed out that a cessation of gas cap production from the pool would represent a loss of 11 per cent of the total gas processed through the plant and would mean a loss of income of approximately $500,000 per year to the Ghost Pine Unit.

Gulf submitted that a reduction of this magnitude would result in a premature shut down of the plant and some pools in the area would reach their economic limit sooner because the cost of these shared facilities could no longer be assigned in part to the Rowley Pekisko A Pool. No estimate was provided of the amount of gas which would be thus rendered unrecoverable.

9.3 Views of the Examiners

The examiners are not convinced that a significant loss of gas would occur. It appears probable that other sources of gas supply may be available to Gulf and, in any case, the Rowley Pekisko A Pool gas cap would eventually return to production presumably to the Ghost Pine Plant. In any event the avoidance of loss of income at the plant would not justify waste at the subject pool.

10.0 RESPONSIBILITY FOR OPERATIONS

10.1 Views of Blake

In its application for cessation of gas cap production from the well, AMERADA HONOLULU ROWLEY 2-16-32-20, Blake applied for amendment of Approval No. 1836 to permit the delivery of gas produced with the oil to the Ghost Pine Unit or the injection of this gas into the Rowley Pekisko A Pool gas cap at Blake's option.

Blake stated that it has the right to produce the oil and gas but hat it has an obligation to deliver this gas to the Ghost Pine Unit.

10.2 Views of Gulf

Gulf requested that clause 2 in Approval No. 1836 be amended to read hat injection or sale of the produced gas be at the discretion of the Ghost ine Unit, not Blake. Gulf claimed that the gas cap gas and solution gas prouced from the Rowley Pekisko A Pool are owned by the Ghost Pine Unit. Gulf rew attention to Approval No. 1836 which gives authority to Blake to dispose f gas produced as Blake sees fit, but claimed that this right had been erronously assigned through a combination of circumstances including a change of wnership and an oversight on behalf of Gulf. It claimed that the Ghost Pine nit should have control of the operation of the 2-16 well.

10.3 Views of the Examiners

An approval of a scheme is different from most Board orders in that ather than making a quasi legislative provision or directing that something e done, the approval authorizes the implementation of a program devised by the perator who has presented it to the Board. The Board expects the operator o carry out his scheme as it was presented employing his knowledge of the cheme and his skills as a capable operator. Where the Board attaches terms nd conditions it sets the limits it considers desirable within which the perator shall exercise his knowledge and skills. The examiners believe it ould not be proper for the Board to attach a condition to an approval that ould in effect require Blake to carry out its scheme subject to the directions f the Ghost Pine Unit.

1.0 GOOD PRODUCTION PRACTICE

11.1 Views of Blake

Blake indicated that permission to produce the Rowley Pekisko A Pool n accordance with good production practice would provide the incentive necesary to develop additional reserves in the pool and would result in improved ecovery. As the allowables of wells in the pool are near the minimum allownces, it is not economically attractive to drill those locations which are eologically attractive. A comparison of two of the depletion cases studied y Blake also suggest that, if gas cap production should continue, granting f GPP to the oil wells would result in recovery of an additional 340 MSTB rom the presently developed portions of the pool.

11.2 Views of Gulf

Gulf did not oppose the application for good production practice fter it ascertained that it was made on the basis of conservation gain and ith the purpose of developing additional reserves.

11.3 Views of the Examiners

The examiners agree with Blake that the Rowley Pekisko A Pool is ot fully developed and that the prospect of increased production rates would be an incentive for further drilling which could, in turn, result in proving up of additional oil in place and improved drainage of the reservoir. In the opinion of the examiners, however, it is not necessary to grant GPP to the wells. The examiners have recommended the setting of a substantially increased reserve for the pool (previously 591 MSTB; now 1,640 MSTB) and the resultant increase in proratable reserve alone would increase the pool reserve allocation from 114 barrels per day to 450 barrels per day. This increase, combined with the current favourable market outlook for Alberta crude oil, will probably result in allowables to the wells which approach or exceed their capability to produce, and which are large enough to provide an incentive for further development of the pool.

With regard to the conservation benefits which the applicant claimed would result if GPP was granted, the examiners do not believe that the evidence is sufficiently clear to prove this. The Blake estimates depend entirely upon assumptions of pressure and productivity decline, without proof that these will actually occur. As effective pressure communication is uncertain between the gas cap and the oil accumulation, the examiners believe that there is no basis for granting GPP to the oil wells at this time.

12.0 EXAMINERS FINDINGS

1. Geologic evidence supports the existence of gas cap and an oil bearing section in the Rowley Pekisko A reservoir.

2. The examiners find that there are insufficient data available to determine if there is, or is not, effective fluid migration between the gas cap and the oil accumulation.

3. Reliable pressure surveys are necessary to determine the amount of pressure communication and its effects on the recovery of oil from the Rowley Pekisko A Pool.

4. There is insufficient evidence of any beneficial effects, to either stimulate development or to achieve conservation of oil, to warrant granting GPP to the oil wells.

5. Examiners R. G. Evans and R. W. Edgecombe find that there is no convincing evidence to suggest that continued concurrent production will have significant deleterious effects on the ultimate oil recovery during the producing life of the Rowley Pekisko A Pool.

6. Examiners R. G. Evans and R. W. Edgecombe find that Approval No. 1837 should be rescinded since Blake apparently does not hold the gas rights in the Rowley Pekisko A Pool.

7. Examiner N. A. Macleod finds that the evidence submitted is insufficient to warrant continuation of Approval No. 1837 in view of the applicants concern of its adverse effect upon conservation.

13.0 RECOMMENDATIONS

The examiners recommend the following:

1. That Application No. 6813 be denied.

2. That Application No. 6814 be granted by rescinding Approval No. 1837 ich grants concurrent production in the Rowley Pekisko A Pool.

3. That the original gas in place reserves for the Rowley Pekisko A Pool set at 50 Bcf.

4. That the initial recoverable crude oil reserves for the Rowley Pekisko Pool be set at 1,650 MSTB, as detailed on the attached tabulation.

5. That annual pressure surveys be conducted on four oil wells determined hrough consultation between Blake and the Board staff.

Examiners R. W. Edgecombe and R. G. Evans recommend:

6. That because there is no technical reason for requiring discontinuance f concurrent production in the Rowley Pekisko A Pool, if an application for oncurrent production of the pool were submitted by the operators of the Ghost ine Unit and if no new evidence were to be adduced which would indicate to the ontrary, it should be granted.

4.0 BOARD DECISION

The Board agrees with, and has decided to adopt, the first five ecommendations set out above. With regard to the sixth recommendation, the oard is inclined to agree with Mr. Edgecombe and Mr. Evans but has decided o defer decision on the matter until there is an application before the Board.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

TED at Calgary, Alberta
ly 10, 1973

ULTIMATE RESERVE FACTORS

(as of ~~December 31, 19~~__)
May 1, 1973

FIELD ROWLEY

POOL PEKISKO A MECHANISM (1) ____

Cut-offs ∅ Upper | Lower %				2
K Upper | Lower md				0.1
G/O Interface			-1714	
O/W Interface			-1804	
Area @ G/O				
Area used to det'n Rock Vol, A				
Oil Zone Rock Volume, V				
Gas Zone Rock Volume				
Validated Area			4480	
H, h			38.2	
∅			0.069	
1-Sw			0.70	
1/Boi			0.86	
N thousands of stbbl (2)			55,100	
Ri			0.03	
Ri N thousands of stbbl (2)			1,650	
Np % N				
Average Well Depth				
Minimum Allowance				

(1) Where more than one recovery mechanism (i.e. - water flood, partial gas flood, primary, etc.) is operating in a pool, a summary sheet entitled "Pool Total" is also provided.

(2) For portion of the reservoir subject to this mechanism.

ENERGY RESOURCES CONSERVATION BOARD

Decision 73 - 13
Application No. 6408

Exemption from Sulphur Recovery Guidelines Crossfield East Gas Processing Plant

1. THE APPLICATION AND HEARING

Amoco Canada Petroleum Company Ltd. applied under section 38, of The Oil and Gas Conservation Act for exemption of the Crossfield East Gas Processing Plant from the sulphur recovery efficiency guidelines prescribed in Board Informational Letter No. IL 71-29.

The application was heard on March 22, 1973 by the Energy Resources Conservation Board with G. W. Govier, P. Eng., V. Millard and D. R. Craig, P. Eng., sitting.

APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Amoco Canada Petroleum Company Ltd.	A. Neidermayer, P.Eng. T. Kitagawa, P.Eng.	Amoco
Department of the Environment	S. Dobko, P.Eng.	Department
Board Staff	L. A. Mazurek, P.Eng. T. W. Nazarko, E.I.T.	

There were no interventions respecting the application.

2. BACKGROUND

The composite Crossfield East Gas Plant consists of two plants processing gas from separate reservoirs. The Elkton Plant processes sweet rich gas from the Crossfield East Elkton Pools and the D-1 Plant processes sour lean gas from the Crossfield East Wabamun A Pool.

In January, 1964, Approval No. 656 was issued to Amoco for a scheme to process 27.5 million cubic feet per day of sweet Elkton gas. Subsequent to an application to the Board, dated

August 3, 1966, the Board issued Approval No. 903, which granted approval of a further scheme by Amoco to process 105 million cubic feet per day of sour Wabamun gas with a maximum sulphur content of 1540 long tons per day. The minimum sulphur recovery efficiency set under the approval was 95 per cent Pursuant to Board Approval No. 1345, dated September 8, 1970, the composite plant was expanded to its present maximum inlet capacity of 182 million cubic feet per day, to handle 60 million cubic feet per day in the Elkton Plant and 122 million cubic feet per day in the D-1 Plant. The maximum permitted sulphur inlet rate is at present 1800 long tons per day with a minimum sulphur recovery requirement of 95 per cent.

3. DEFINITION OF ISSUES

3.1 Sulphur Recovery

The issue of principal concern in the subject application is the future sulphur recovery efficiency to be required of the D-1 Plant. The guidelines, set out in IL 71-29, state that a plant processing a favourable quality acid gas containing from 1000 to 4000 long tons of sulphur per day should, by December 31, 1974, be recovering from 98 to 99 per cent of the sulphur in the inlet gas. The Board, by approximate interpolation based on a maximum inlet capacity of 1800 long tons per day, interprets the guidelines to require a recovery of 98 per cent and accordingly, considers the application to be one for exemption from this level.

3.2 Ground Level Concentration of SO_2

A further matter considered at the hearing concerns the meeting of the calculated ground level sulphur dioxide concentration standard of 0.20 parts per million, set by the Department of the Environment.

4. SUBMISSION OF THE APPLICANT

4.1 Sulphur Recovery

The application for exemption from the guidelines was based on:

(a) the contention of an absence of any indicated adverse environmental effects from plant operations,

(b) the poor economics claimed to result from the addition of a tail gas clean-up process required to meet the guidelines, and

(c) the unsatisfactory resource trade-off which would require the consumption of a more valuable resource to recover a less valuable resource.

Amoco's views with respect to item (a) above are given in Section 4.2.

Amoco submitted that in an attempt to improve sulphur recovery efficiency, minor modifications have been made to the sulphur plant during the past year but that these modifications will not increase the recovery efficiency much above the current recovery level of 96 per cent. It stated that a tail gas clean-up process would be required to increase the recovery significantly beyond this level.

Amoco further submitted that it did not believe that the economics of the sulphur plant should be considered separately from its total production and processing project. It contended that projects are conceived only on total economics and although the sulphur plant economics may be acceptable, the overall economics of the project may be unacceptable. It stated that the owners of the D-1 plant must recover an additional $15,000,000 of the initial $36,000,000 overall D-1 project investment to attain a payout status. It stated that any additional investment to reduce sulphur dioxide emission would impose an added economic burden on the project to a point where continued operations of the project may not be feasible.

Amoco estimated that the rate of return of the overall D-1 project from 1958 to 2002, would be 4.5 per cent, assuming the present method of operation. It was similarly estimated that the rate of return would be reduced to 1.7 per cent and 0.9 per cent respectively with the installation of tail gas clean-up facilities required to achieve a recovery of 98 and 99 per cent. These calculations were based on Amoco's sulphur price and sales forecast, a gas price schedule that escalates from 13.4¢ per Mcf to 18.7¢ per Mcf and a condensate price schedule that escalates from $1.41 per barrel to $3.34 per barrel for the period 1968 to 1988.

In response to a request by the Board, Amoco, following the hearing, submitted some revised calculations with respect to the capital investment and annual operating costs for three tail gas clean-up processes, that could be installed, to achieve a 98 to 99 per cent recovery. Of these the IFP process required the lowest capital expenditure with an investment of $2,854,000 and an annual operating cost of $541,400 to achieve 98 per cent recovery or an investment of $5,926,000 and an annual operating cost of $767,600 to achieve 99 per cent recovery.

Amoco presented a year by year cash flow analysis from 1968 to 2002 for the sulphur plant with the addition of the IFP process for the 98 and 99 per cent recovery levels. The analysis assumed a constant future sulphur price of $5.00 per long ton and an annual sulphur sales volume of 60 per cent of production through the year 1988. In that year production would cease but sales from the stockpile would continue at the same sulphur price and annual sales level until the stockpile was depleted in the year 2002. The analysis showed that cash flows would become negative in 1983 for the 98 per cent recovery case and in 1980 for the 99 per cent recovery case. In a further submission to the Board, following the hearing, Amoco calculated the rate of return based on this cash flow analysis for the sulphur plant alone to be 54.7 per cent for the 98 per cent recovery case and 54.3 per cent for the 99 per cent recovery case.

In conclusion, Amoco was of the belief that the incremental conservation of sulphur with a tail gas clean-up process would not be justified when compared to the electric energy and steam costs required to operate a tail gas clean-up process. Amoco estimated for the 98 per cent recovery case that an additional 30 long tons per day of sulphur having an approximate value of $58,000 per year would be recovered whereas the electric energy and steam cost would be approximately $120,000 per year. It stated that the use of a more valuable resource to recover a less valuable resource would not be in keeping with a philosophy of total resource management.

4.2 Ground Level Concentrations of SO_2

To ensure that calculated ground level concentrations of sulphur dioxide do not exceed 0.20 parts per million the applicant suggested three possible alternate plant modifications that could be made, without the addition of a tail gas clean-up process.

The first alternative would be to construct a new and higher stack. Amoco calculated that it would be necessary to replace the existing three hundred foot stack with one having an additional height of one hundred feet and that it would be necessary to retain the present stack top temperature requirement of 1200°F to maintain the maximum calculated ground level concentration of sulphur dioxide below 0.20 ppm at current emission rates. The new stack and incinerator modifications required for this purpose would cost an estimated $1,100,000.

The second alternative would be to add a third converter to the existing facilities. Amoco reported that it has been conducting pilot studies at the plant with the use of a third converter to determine the continuous recovery capabilities under plant operating conditions. It stated that preliminary results have indicated that sulphur recovery efficiencies would be increased from 96 to 97.5 per cent at an estimated cost of $2,045,000.

The third alternative proposed would be to cut back production under adverse atmospheric conditions. Studies by the applicant show that the calculated ground level sulphur dioxide concentrations in the area of the plant under actual operating conditions have indicated maximum ground level concentrations of 0.3 ppm. It stated that during adverse atmospheric conditions the plant throughput could be reduced from 1600 long tons per day to 979 long tons per day of sulphur. However, Amoco suggested that during the cutback operation and subsequent increase in throughput, plant upsets could occur and cause an increase in sulphur dioxide emissions. It added that the timing of cutbacks in production would also pose problems.

Amoco stated that it had conducted annual soil, vegetation and infrared surveys since 1970 and that it had monitored ambient air quality in the area since before the plant was constructed. It indicated that the results of the surveys have shown no adverse effects on the vegetation from sulphur dioxide emissions and that ground level concentrations have been within the Department of the Environment's air quality standards except for a few isolated cases. Amoco stated at the hearing that in August, 1972 it noted some vegetation stress due to sulphur dioxide emissions in a localized area south-west of the plant, but that the condition cleared up by the end of August.

Amoco submitted that it had interviewed the residents in the area of the plant, yearly, since 1969 to discuss any problems related to the plant operation. It stated that it has received 16 complaints during the last 3 years, all of which have been related to operations other than sulphur dioxide emissions from the incinerator stack. The applicant stated that all complaints had been promptly investigated by the operator.

Following the hearing Amoco submitted a complete resume of the compaints it had received and these indicated that eight complaints were with respect to sulphur dust, four complaints were regarding hydrogen sulphide odour, two complaints were related to other odours, one complaint with regard to hydrocarbon contamination and one complaint respecting operating noise levels.

4.3 Alternative Application

Amoco requested that if the application for exemption from the sulphur recovery guidelines does not meet with the Board's approval that it should be considered as an application requesting an extension to December 31, 1975 to provide for the submission of another application for exemption from a requirement of a higher sulphur recovery efficiency.

5. CONCERNS OF THE DEPARTMENT

The primary concern expressed by the Department was with respect to the high calculated ground level concentrations of sulphur dioxide which indicate levels greater than the present standard of 0.2 ppm averaged over 30 minutes when the calculations are based on the current sulphur plant recovery efficiency of 96 per cent. The Department noted that the calculated levels were even higher, something in excess of 0.4 ppm, when the present approved sulphur recovery efficiency of 95 per cent was considered. It also noted that these calculations do not take into consideration such operating anomalies as plant upsets, period of startup and shutdown, catalyst regeneration and nomination changes which could result in excessive emissions.

From recent knowledge gained on sulphur recovery plants, the Department expressed concern that emissions could be greater than 50 per cent above normal for periods of 2 to 3 hours during operating anomolies and could result in calculated levels in excess of 0.6 ppm.

The Department also expressed concern with respect to the reported sulphur dioxide stress on vegetation reported by Amoco and indicated to the Board that since the plant is located near a small urban center and in the midst of a good agricultural area, it is mandatory that theoretical calculated levels should not be greater than 0.2 ppm at anytime regardless of the problems that may be experienced at the plant. Several methods are available to the applicant to gain compliance with the calculated level of 0.2 ppm of sulphur dioxide and the Department submitted that compliance with the sulphur recovery guidelines would be important in achieving this endpoint.

6. VIEWS OF THE BOARD

6.1 Sulphur Recovery

The Board has considered the economic, resource trade off, environmental and technical arguments submitted by Amoco with regard to its request for an exemption from the higher sulphur recovery efficiency requirements.

The Board reiterates its view, expressed in recent decision reports with respect to similar applications, that a history of an acceptable impact on the surrounding environment as a result of satisfactory sulphur plant operations is not considered a primary basis for exemption from the guidelines. The sulphur recovery guidelines are designed to provide for a sulphur recovery level that is as high as is practical having regard for both economics and sulphur recovery technology.

The Board has examined the economics of the operations of the sulphur plant with the addition of a tail gas clean-up facility to determine the discounted rate of return after 1974. The remaining undepreciated value of the existing facilities was determined by calculations based on a ten per cent per year straight line depreciation allowance subject to available cash flow. The Board estimated that an investment of $3,200,000 would be required to increase the sulphur recovery efficiency to 98 per cent. This compares to Amoco's estimate for 1974 of $2,940,000. The Board's analysis was based on a total investment in 1975, including carry forward of undepreciated investments, of $5,042,000. This capital investment figure would be reduced to $3,942,000 if a credit of $1,100,000 were allowed for the fact that with the tail gas facility a new stack would not be necessary. This is discussed in Section 6.2. The Board also estimated the total undiscounted operating cost from 1975 to 1988 to be $18,543,000 which compares to the applicant's estimate of approximately $17,966,000. Both of these operating costs were escalated at 3 per cent per year and do not include sulphur slating costs. The Board based its analysis on its own sulphur sales and price forecast and used the applicant's sulphur production forecast. The data used in the Board's analysis are given on Table I.

The economic evaluation at a royalty rate of $16^2/3$ per cent indicated a discounted rate of return before taxes of greater than 30 per cent on the overall sulphur plant operation. The Board also carried out an economic evaluation using a more conservative sulphur price and sulphur sales forecast.* This resulted in a discounted rate of return before taxes of 23 per cent. The rate of return in each of these cases would be approximately 8 percentage points more if credit for a new stack was allowed. The Board notes that a more favourable rate of return would have resulted if the applicant's capital and operating cost estimates had been used in the Board's economic analysis.

The Board also made an economic analysis of the overall D-1 project operation from 1975 to 1988 in the same manner as described for the sulphur plant operation by using the applicant's data combined with the Board's sulphur sales and sulphur price forecasts. The discounted rate of return before taxes on the overall project was determined to be 14 per cent. The Board used the applicant's gas price forecast in this evaluation although it believes it to be pessimistic and not in keeping with the generally accepted outlook of rapidly rising gas prices.

As indicated by Amoco at the hearing, and by its own investigation the Board does not believe that the addition of a third stage of conversion would achieve a continuous recovery of 98 per cent with present Claus technology. Hence, the Board did not evaluate this alternative as a means of satisfying the guideline requirements.

The Board has considered the argument that incremental sulphur recovery is not justified having regard for the related increased consumption of other Alberta resources. The Board does not agree with Amoco that a comparison of incremental utility costs of a tail gas facility with the value of the incremental sulphur conserved is an acceptable method of evaluating the resource trade-off. Total utility costs are included in the overall sulphur plant economics and in the Board's view the only matter at issue is the overall Provincial balance of resources required to achieve the increased sulphur recovery.

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* The conservative forecast assumes a constant sulphur sales volume of 50 per cent of production and a sulphur price of $7.00 per long ton in 1975, escalating to $10.00 per long ton by 1978 and remaining constant thereafter.

Table II shows the Board's estimate of the resource gain and loss associated with a tail gas sulphur plant facility. The major gain is the additional sulphur recovery of 36 long tons per day at maximum plant throughput rates. In addition, as discussed in section 6.2, the decrease in sulphur dioxide emissions results in less gas being required for incinerator fuel. This represents a gain of approximately one million cubic feet per day. The Board estimates that the additional electric energy required for the 98 per cent recovery would be in the order of 24,000 KWHR per day. Assuming that coal would be used to generate the electric energy, approximately 17 tons per day of coal would be consumed at a thermal power plant.

As shown in Table II, the net resource gain at current market value is $117,000 per year. In fact the increased marketable gas made available through lower sulphur dioxide emissions more than compensates for incremental coal requirements on both a total energy content and a current value basis. The Board notes that in similar cases no fuel gas saving would be realized since the minimum permitted stack exit temperature is 1000°F. The Board concludes that the overall resource trade-off strongly favours the increase in sulphur recovery.

Furthermore, the consumption of 17 tons per day of coal for power generation at a thermal electric power plant would result in sulphur emissions to the atmosphere of only 11 long tons per year. Compared to a potential conservation of 36 long tons per day of sulphur at the Crossfield East Gas Plant, the net reduction in sulphur emissions per year would be virtually 100 per cent.

6.2 Ground Level Concentration of SO_2

After reviewing the results of environmental studies and air quality monitoring programs the Board is of the opinion that there has been no significant environmental damage in the vicinity of the plant due to sulphur dioxide emissions from the incinerator stack. The low number of complaints with respect to actual plant operations and the absence of any interventions from local residents at the hearing suggest satisfactory plant operations.

Like the Department, the Board is concerned that monitoring results indicate sulphur dioxide concentrations as high as 0.7 ppm during August 1972. The Board accepts that the conditions that gave rise to these values are not indicative of normal plant or field operations. It also notes that Pasquill incinerator stack calculations using the present maximum sulphur dioxide emission rate and the present stack height indicate calculated ground level sulphur dioxide concentrations of 0.41 ppm. Thus additional plant modification is required to adhere to minimum calculated ground level sulphur dioxide concentration standards of 0.20 ppm to prevent cases of high sulphur dioxide ground level concentrations from occuring.

The Board has considered the alternatives presented by the applicant, to ensure adherence to the calculated ground level concentration standards and to satisfy the guidelines. The Board is of the view that only the addition of a tail gas clean-up process would adequately satisfy the sulphur recovery requirements. Furthermore, Pasquill incinerator stack calculations at a maximum sulphur dioxide emission rate of 72 LTD corresponding to a sulphur recovery efficiency of 98 per cent indicate that the calculated ground level sulphur dioxide concentration would be 0.13 ppm at a stack top temperature of 1200°F and 0.14 ppm at a stack top temperature of 1000°F. Thus, at this recovery level Provincial Air Quality Standards would be met, the stack gas exit temperature could be reduced to 1000°F and no stack modifications would be required. Therefore, the estimated cost for a new stack of $1,100,000 may be considered as a credit toward the installation of a tail gas clean-up process.

The Board concludes that sulphur recovery at a 98 per cent level is warranted. It recognizes that increased operating costs will be required to achieve the higher recovery but is of the view that the sulphur plant will remain economic. Furthermore, the Board is satisfied that the overall D-1 project will remain economic and believes that the cost of additional sulphur recovery is justified to conserve a natural resource and to reduce total sulphur dioxide emissions.

6.3 Alternate Application

The Board is not prepared to grant Amoco the opportunity of making another application for exemption by December 31, 1975 as requested in the application.

7. DECISION

The Board denies the application by Amoco for exemption of the Crossfield East Gas Processing Plant from the sulphur recovery efficiency guidelines set out in Board Informational Letter No. IL 71-29 and the request to permit another application by December 31, 1975. The Board requires that the Crossfield East Plant meet a sulphur recovery requirement of 98 per cent by December 31, 1974.

The Board expects that, in accordance with Informational Letter No. IL 71-29, Amoco will apply prior to September 30, 1973, unless a later date is stipulated by the Board, for approval of the proposed modifications necessary to meet the 98 per cent sulphur recovery requirement.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

Dated at Calgary, Alberta
July 12, 1973

TABLE I

Data Used for Board Evaluation of Amoco Sulphur Recovery Plant Economics

Year	Investment ($ x 10^3)	Annual Operating Cost ($ x 10^3)	Annual Sulphur Production (LT x 10^3)	Percentage of Sulphur Production Sold	Plant Netback Sulphur Price ($/LT)
1975	3,200*	1,084	577	50	9.00
1976		1,116	577	50	10.00
1977		1,150	577	50	11.00
1978		1,185	577	52	12.00
1979		1,220	577	54	12.00
1980		1,257	577	56	12.00
1981		1,294	577	58	12.00
1982		1,333	577	60	12.00
1983		1,373	577	60	12.00
1984		1,414	577	60	12.00
1985		1,475	577	60	12.00
1986		1,500	577	60	12.00
1987		1,546	577	60	12.00
1988		1,592	577	60	12.00

* Does not include carry forward of undepreciated investment.

TABLE II

Daily Resource Balance For A Tail Gas Sulphur Plant Facility

Resource Gain	Volume/day	Current Market Value ($/yr.)
Sulphur (Long Tons)	36	79,000
Gas [(1)] (MMcf)	1	53,000
Total Gain		132,000
Resource Loss		
Coal[(2)] (Tons)	17	15,000
Net Gain		117,000

(1) Reduced Volume of fuel gas required for incinerator

(2) Assumed that coal would be used to generate the additional electric energy

ENERGY RESOURCES CONSERVATION BOARD

Decision 73 - 14
Application No. 6823

INCREASE IN THE MAXIMUM PERMITTED HYDROGEN SULPHIDE INLET RATE AT THE GOLDEN SPIKE GAS PROCESSING PLANT

1. THE APPLICATION AND HEARING

Imperial Oil Limited applied pursuant to section 38, subsection (1), clause (b) of The Oil and Gas Conservation Act for amendment of Approval No. 1531 to authorize an increase in the maximum permitted hydrogen sulphide inlet rate and the maximum permitted sulphur dioxide emission rate at the Golden Spike Gas Processing Plant, located in the North-west quarter of Section 22, Township 51, Range 27, West of the 4th Meridian. Section 38, subsection (2) of The Oil and Gas Conservation Act requires that the Board, prior approving an application made under section 38, subsection (1), clause (b) of the Act, refer the application to the Minister of the Environment for his approval with respect to matters of the environment. The application has been referred to the Minister of the Environment and is also being considered as an application made pursuant to section 4, subsection (1), clause (a) and section 4.1, subsection (1), of The Clean Air Act; and section 4, subsection (1), clause (f) and section 4.1, subsection (1) of The Clean Water Act for permits for construction and licences for operation of the proposed facilities. Imperial requested that the maximum hydrogen sulphide inlet rate be increased from 2.8 thousand cubic feet per day to 110 thousand cubic feet per day (hereinafter abbreviated "Mcfd") and that the maximum sulphur dioxide emission rate be increased from 0.211 long tons per day to 8.28 long tons per day. The sulphur dioxide would be emitted to the atmosphere through a new flare stack 200 feet in height. Imperial also requested that it be granted permission to use up to 300 Mcfd of sour solution gas from the Golden Spike D-2 A and D-3 B Pools (hereinafter called the "D-2 A" and "D-3 B Pools") as fuel gas for the 200-foot acid gas flare stack. The sulphur dioxide air qualtity monitoring network in the plant vicinity would be increased from one continuous monitor in operation for one month of each year to one continuous monitor to be in operation for six months of each year. The number of exposure cylinders would be increased from nine to 12 stations.

The application was heard at the Law Courts, Edmonton, Alberta on April 6, 1973, by the Board with G. W. Govier, P. Eng., D. R. Craig, P. Eng., and G. J. DeSorcy, P. Eng. sitting.

2. SUBMISSIONS

Submissions in opposition to the application were filed by a number of groups and individuals listed in Attachment 1 to this report. Most of the interveners live in the vicinity of the Golden Spike Plant.

In view of the large number of objections to the application, the Board modified its normal hearing procedure. It registered and accepted all of the interventions whether or not a representative of the intervention was actually present at the hearing. It selected those interventions which it considered to be the most comprehensive and dealt with those in the normal manner. Any other intervener who wished to present his submission at the hearing was then permitted to do so. All interventions were therefore not attested to by a witness but were registered and given full consideration by the Board.

The following appeared at the hearing:

	Abbreviation Used in Report	Represented by
Imperial Oil Ltd.	Imperial	D. E. Lewis, Q.C. W. Willows D. J. McEachern, P. Eng. D. G. Hay
Irene Goebel et al		I. Goebel J. Adolph
Merril McDonald		M. McDonald
K. V. Sinclair and R. Sinclair		K. V. Sinclair R. Sinclair
A. K. Miller		A. K. Miller
Unifarm		W. D. Lea
K. D. Hage et al		K. D. Hage R. G. Ironside D. J. Wilson, P. Eng.
W. Jappsen		W. Jappsen
Richard Secord		R. Secord
F. W. Michna		F. W. Michna
R. D. Morin		R. D. Morin
John Vanthoff		J. Vanthoff
Leila Howell		D. C. McDonald
J. Boje		J. Boje
Department of the Environment	Department	S. L. Dobko, P. Eng.
Board Staff		N. A. Macleod, Q.C. P. D. Larbalestier, P. Eng. R. B. Dunbar, P. Eng.

3. BACKGROUND

The Golden Spike gas processing plant is presently utilized as part of an enhanced crude oil recovery solvent flood scheme operating in the Golden Spike D-3 A Pool of the Golden Spike Field. This scheme is operated under the terms and conditions of Board Approval No. 1420. The approval requires the injection of fluids to the Golden Spike D-3 A Pool (hereinafter called the "D-3 A Pool") in sufficient volumes to maintain a suitable balance between fluids injected to and fluids withdrawn from the pool.

Solvent for the enhancement of crude oil recovery from the D-3 A Pool is produced at the plant by processing solution gas from the D-3 A Pool and pentanes plus from the Judy Creek gas processing plant. Dry gas is also injected to the reservoir and is comprised of processed solution gas from the D-3 A Pool, gas from the Devon gas processing plant in the Leduc-Woodbend Field, gas purchased from Trans-Canada Pipelines Limited and supplemental local sources of supply. In the past, some injection gas has been obtained from the Viking, Blairmore A and D-1 A Pools in the Golden Spike Field.

Approval No. 1531, for the processing of gas used for the injection scheme in the Golden Spike Field does not currently authorize the processing of gas from the Golden Spike D-1 A Pool (hereinafter called the "D-1 A Pool"). However, prior to June 9, 1972 processing of gas from the D-1 A Pool was permitted at rates up to 4.0 MMcfd. The acid gases removed from this gas were flared at the existing 60-foot flare stack at sulphur dioxide emission rates up to 6.02 long tons per day. As a result of an application by Imperial, dated April 18, 1972, Approval No. 1531 was amended on June 9, 1972 so that it no longer permits the processing of gas from the D-1 A Pool. The approval now provides for the processing of Basal Quartz gas from the Golden Spike Blairmore A Pool (hereinafter called the "Blairmore A Pool") at rates up to 7.0 million cubic feet per day (MMcfd) and requires that the acid gases removed during the processing be flared through a flare stack 65 feet in height at emission rates not exceeding 0.211 long tons of sulphur dioxide per day.

Imperial submitted the subject application, dated December 12, 1972, for an amendment to Approval No. 1531, to again permit the processing of sour gas from the D-1 A Pool at rates up to 5.0 MMcfd when sufficient quantities of gas from the Blairmore A Pool are not available. A new stack 200 feet in height would be installed to flare the acid gas at sulphur dioxide emission rates up to 8.28 long tons per day. No other construction would take place. The Board and the Department reviewed the application and found it to be deficient in regard to information respecting the waste water treatment and disposal facilities at the plant. Upon receiving the above information, the Board issued a public notice of the application on February 9, 1973. The notice was advertised in several Alberta newspapers and, in addition, was sent directly to several people living in the vicinity of the Golden Spike Plant. Several objections to the notice were filed and as a result the Board decided to publicly hear the application. The Board issued notice of the hearing on March 12, 1973, and published the notice in the major Alberta newspapers and sent the notice directly to people living in the vicinity of the plant.

4. DEFINITION OF ISSUES

The Board considers the following to be the main issues respecting the application:

(a) the adequacy of the existing Provincial environmental standards,

(b) the need for a special environmental standard in the Golden Spike area,

(c) the need for special environmental impact studies by Imperial,

(d) the adequacy of the proposed Imperial facilities having regard for the existing or appropriate environmental standards,

(e) the use of sour gas from the Golden Spike D-2 A and D-3 B Pools as fuel for the acid gas flare stack,

(f) the alternatives open to Imperial and their suitability, and

(g) environmental problems related to aspects of the operation other than the facilities for flaring of acid gas.

5. ADEQUACY OF EXISTING PROVINCIAL ENVIRONMENTAL STANDARDS

5.1 Views of Imperial

Imperial stated that no apparent detrimental effects have resulted from the present operation at levels within existing Provincial environmental standards for maximum ground level concentrations of sulphur dioxide. In view of this, Imperial concluded that the existing standards are adequate. Imperial noted that the Provincial standards conform with the levels accepted by the Government of Canada except that the Federal standards do not specify a half-hour maximum concentration.

Imperial submitted that, in general, based on past experience, the Pasquill calculation method for designing elevated flares yields higher values of maximum ground level concentration of sulphur dioxide than have been measured in the field. Imperial pointed out that although a number of methods are available, only the Pasquill method was used for stack design since it is the only calculation method accepted by the Department. Imperial acknowledged in reply to questioning that, although a degree of uncertainty related to variations in topography and climatic conditions exists in results based on the Pasquill method, the method has proved to be adequate, if not conservative. In reply to further questioning, Imperial pointed out that the Pasquill method provides a means of estimating only the half-hour maximum concentration, and that the levels for longer periods, such as one hour or twenty-four hours, must be determined by other means.

5.2 Views of the Interveners

Mrs. K. V. Sinclair and Mr. R. Sinclair (hereinafter referred to as "the Sinclairs") submitted, in their brief, that the adequacy of the existing Provincial environmental standards for maximum ground level concentration of sulphur dioxide is in doubt because of the general lack of knowledge regarding the effects of sulphur dioxide and other emissions on the environment. They submitted that it is unrealistic to base air quality standards on laboratory experiments under ideal conditions since ideal conditions never occur in nature. The Sinclairs stated that sulphur dioxide can react with substances in the atmosphere to form compounds, the effects of which are more harmful than the sum of the effects of each component, and that, in view of this type of reaction, extreme care should be taken to set safe levels. With reference to the literature, they stated that average values of ground level concentrations of sulphur dioxide are meaningless since plants show acute damage when subjected to high concentrations over a short time period and since the effect of sulphur dioxide on the acidification of lakes and rivers is cumulative. Acceptable levels of acidity for lakes and rivers in certain portions of Eastern Canada and the United States were quoted from the literature.

With respect to the effects of sulphur dioxide on human beings and animals the Sinclairs stated that research has been carried out only for short term exposures while the long term effects have been extrapolated from statistics. They stated that laboratory research has little application to real life situations. They submitted that there is strong evidence to show that different tolerance levels are exhibited by different animals and that sensitivity to sulphur dioxide increases with repeated exposure. The Sinclairs submitted that a direct correlation is indicated between mortality and morbidity among human beings and air pollution occurrences. They cited references to studies of the effects of sulphur dioxide at various concentrations for various time periods.

The Sinclairs contended that proper standards would be difficult to set and questioned whether any level would be safe considering the general lack of knowledge regarding the effects of sulphur dioxide. They stated that the wide variations in standards from country to country indicated confusion and suggested that harmful effects may begin at levels that are lower than existing standards.

In their submission of intervention, Mrs. I. Goebel and Mr. J. Adolph pointed to certain detrimental effects of sulphur dioxide on plant and animal life. They considered the plants most sensitive to sulphur dioxide to be wheat, oats, barley and alfalfa, and stated that levels of 1.0 parts per million (ppm) for one hour will cause leaf tissue collapse, chlorosis, growth pattern alteration, and altered mineral uptake. They stated that sulphur dioxide affects animal respiratory systems, notably membranes of the nasal passages and lung tissue.

Mrs. Goebel and Mr. Adolph submitted that people are unable to detect levels of sulphur dioxide by odour below levels of one to three ppm but that long term exposure to sulphur dioxide in the range of one to three ppm results in eye and nose irritation, increased occurrence of asthma, and worsening of the conditions associated with emphysema. They stated that short term exposure to a level of six ppm results in paralysis and major tissue damage of the respiratory organs.

Dr. Hage et al submitted that people should not be exposed to the emission of sulphur dioxide when there has been insufficient research on its harmful effects. They stated that a large number of reports have been generated on the subject and many experiments and studies have been done in the laboratory, but controlled laboratory conditions do not replicate actual conditions in the environment. They suggested that further study is necessary to determine the effects of long term exposure to low concentration levels and short term exposure to high concentration levels of sulphur dioxide. Reference was made to claims of ill-health effects in the area of the Harmattan-Leduc and Pincher Creek gas plants, although the submission acknowledged that it was difficult to link the reported effects with the operation of these plants.

The submission of Dr. Hage et al stated that the literature indicated possible harmful effects from sulphur dioxide emissions and that tolerance levels vary with the age of an individual and other conditions. It said that evidence of the effect on animals and aquatic life is incomplete, conflicting, and difficult to acquire. Dr. Hage et al noted that the Golden Spike area has up to 40 per cent water surface and made reference to studies conducted in the Sudbury area on lake acidity levels.

The intervention of Dr. Hage et al noted that neither Imperial, the Board, nor the Department have conducted any research to determine the possibility of fumigations or short periods of high concentration occurring under stable atmospheric conditions. Dr. Hage et al concluded that the existing government standards are not stringent enough to control the effects of sulphur dioxide emissions.

The interventions of Mr. M. McDonald and Dr. G. Ironside contained comments much the same as those presented in the intervention of Dr. Hage et al. They expressed concern respecting the adequacy of the existing Provincial environment standards because of the general lack of knowledge on the effects of sulphur dioxide emissions. Mr. McDonald claimed concern with the laxity with which government departments have carried out environmental protection. Dr. Ironside stated that stronger preventative measures must be taken and that the onus should not be placed on individuals to prove the harmful effects of emissions after the fact.

5.3 Standards of the Department

The Board has summarized what it believes to be the position of the Department respecting the adequacy of the existing Provincial standards for sulphur dioxide. The Department's view on this issue was not presented at the hearing and the Board's summary of the Department's position is based on the Department's questions and statements made at the hearing and on documents forwarded to the Board by the Department following the hearing. Staff of the Department have reviewed this section of the report and concur with the position stated herein.

The Alberta ambient standards for various pollutants including sulphur dioxide correspond to the maximum desirable levels of the National Air Quality Objectives established under the Federal Clean Air Act. The Alberta standards are more stringent than those set by most jurisdictions and are well below levels which are known to cause adverse human, animal or vegetatio health effects.

A comparison of the Alberta standards with Canadian Federal standards and U. S. Federal Standards is given below:

Time Period	½ hr.	1 hr.	3 hr.	24 hr.	1 yr.
Maximum Sulphur Dioxide Concentration (ppm)					
Alberta	.20	.17	-	.06	.01
Canadian Maximum Desirable	-	.17	-	.06	.01
Canadian Maximum Acceptable	-	.34	-	.11	.02
U. S. Primary	-	-	-	.14	.03
U. S. Secondary	-	-	.50	.10	.02

The Government of Canada defines the maximum desirable level as a long term goal designed to protect the health, safety and well-being of people when the contaminant is present, alone or in combination with other contaminants. The maximum acceptable level is defined by Environment Canada as the level below which there is no known impairment to human health. The Alberta Government has adopted the Federal Government's more stringent maximum desirable levels to ensure that the air quality in the Province is maintained at a high level.

The objectives established by the Federal Government and adopted by the Province have consideration for:

1. Studies of animal effects which show that sulphur dioxide has a toxicological effect on animals at considerably higher concentrations than might be anticipated in even severely polluted atmospheres. Toxicity studies indicate that animals exhibit a higher resistance to sulphur dioxide than man and and therefore animal toxicity is not a factor in limiting concentrations.

2. Studies of human health effects which take into account both short period, high concentration effects derived from laboratory experiments considering a single pollutant, and long term, low concentration effects derived from morbidity and mortality studies where other pollutants such as particulates and synergistic effects are considered.

3. Studies of vegetation effects which indicate that at higher concentrations, plants are more susceptible to sulphur dioxide damage than humans.

The Department noted that sulphur dioxide concentrations causing damage and referenced by some of the interveners are in all cases in excess of concentrations that would be permitted under the Provincial standards.

In summary, the Department's position was that existing Provincial standards are adequate to protect the health and welfare of humans, animals and plants. The Department continually monitors the results of research and studies of the effects of sulphur dioxide and other pollutants and would modify the standards if a need to do so was indicated by such work.

5.4 Views of the Board

The Board agrees with many of the interveners that there remain unanswered questions respecting the long term effects of sulphur dioxide on animal and plant life and that further research in these areas is necessary. However, the Board is aware that the Department has considered these uncertainties in prescribing the Provincial standards and notes that it continuously reviews the adequacy of the existing standards. The Board, therefore, accepts the view of the Department that the existing Provincial sulphur dioxide concentration standards are adequate.

6. THE NEED FOR A SPECIAL STANDARD IN THE GOLDEN SPIKE AREA

6.1 Views of Imperial and the Interveners

Neither Imperial nor the interveners expressed views relative to the need for a special standard in the Golden Spike area. Since it expressed satisfaction with the existing standards, Imperial implied that it saw no need for a special standard. Also, since many of the interveners expressed concern with overall Provincial standards they would not be expected to deal with the matter of special standards for the subject area.

6.2 Position of the Department

The Department takes the position that there is nothing special about the terrain, population density or form of emission and that a special standard for the Golden Spike area is not warranted. In the Department's views, the existing Provincial standards are established to be completely adequate to protect the health, safety and well-being of the people, animals and vegetation in all areas of the Province.

6.3 Views of the Board

The Board concurs with the view of the Department.

7. THE NEED FOR SPECIAL ENVIRONMENTAL IMPACT STUDIES BY IMPERIAL

7.1 Views of Imperial

Imperial stated that it had not made special studies of the environmental impact of the proposed scheme on the Golden Spike area. It referred to a submission by the Canadian Petroleum Association to the Environment Conservation Authority sour gas plant hearings which indicated that no detrimental effects to animals or vegetation result from considerably higher ground level concentrations of sulphur dioxide than are currently permitted by Provincial standards.

In reply to questioning, Imperial stated that it depended on universities and government agencies to supply it with the results of research on the behaviour of plumes in the atmosphere but that more specific information relative to the Golden Spike area could possibly be provided by consulting firms which it has engaged. It stated that it would attempt to provide information respecting the amount of sulphur dioxide which could be expected to reach the ground within a ten mile radius of the plant. Imperial complied with this undertaking after the hearing by filing, with the Board and the interveners, a report prepared by Western Research and Development Ltd. It stated that a recent report on sulphur deposition rates in Alberta indicated that, on a yearly basis, a maximum of about 24 per cent of sulphur emission is deposited within a 25-mile radius of an emitting plant. This deposition mainly results from the scavenging mechanism of rainfall. At the proposed sulphur emission rate of approximately four long tons of sulphur each day (eight long tons of sulphur dioxide), it was calculated that a maximum of about 10 ounces of sulphur per acre would be deposited within the area surrounding the plant due to the proposed emissions. The report stated that this figure should be compared to the annual deposition of from two to four pounds per acre which is the average rate over the earth's surface resulting from natural causes and world-wide industrial activity.

7.2 Views of the Interveners

Many of the interveners implied that special environmental impact studies should be required to evaluate the effects of emissions from the plant on migratory birds, upland game, aquatic and other wildlife in the area. They stated that the general effects of increasing pollutant levels in an otherwise high quality environment should be studied and in addition, the effect of emissions on the park and recreational value of the wooded parts of the area requires investigation. Some interveners suggested that the proposed emissions could have a detrimental effect on surface water and ground water and that the possibility of these effects occurring should be evaluated.

Mrs. Guebel and Mr. Adolph stated that there had not been an ecological study carried out in the area to identify bio-indicators and suggested that such a study would be essential if Imperial is to be held accountable for any possible environmental damage resulting from the operation of the plant.

Mr. R. D. Morin, who did not submit a brief but appeared at the hearing, stated that a report on the environmental effects of sulphur dioxide emissions would be important to have before the scheme was approved, particularly with regard to its effect on the quality of cattle and milk production.

Mr. W. Jappson, who did not submit a brief but appeared at the hearing, asked if Imperial had conducted research into the area of possible detrimental effects on the physical and mental health of people who have been exposed to sulphur dioxide emissions over a long period of time and referred specifically to those people employed at the plant. He stated that his own firm conducted regular medical surveys among its employees and that the results were evaluated periodically.

Dr. Ironside and other interveners questioned Imperial respecting the aerial distribution of sulphur dioxide emitted from the plant. Dr. Ironside stated that Imperial should provide information regarding the amount of sulphur dioxide which would fall to the ground within a ten-mile radius of the plant. Dr. Ironside and other interveners also stated that the acidity of the soil and surface bodies of water in the area should be monitored.

7.3 Views of the Board

The Board believes that the impact of the plant on its surrounding environment will be small. Based on the results of studies being carried out at much larger gas processing plants in the Province the Board expects no significant adverse effects of the facility on plant, animal or human health. The Board is of the view that the standards are sufficiently stringent and, also, that the studies carried out on the biological effects in the vicinity of larger sources of sulphur dioxide emissions provide assurance that acidification of surface bodies of water or soil will not occur. In summary, the Board concludes that special environmental impact studies are not warranted in the Golden Spike Area. However, the Board understands that the need for such studies would be determined by the Minister of the Environment.

8. THE ADEQUACY OF THE PROPOSED IMPERIAL FACILITIES HAVING REGARD FOR THE EXISTING OR APPROPRIATE ENVIRONMENTAL STANDARDS

8.1 Views of Imperial

Imperial's views in this respect were related to the existing standards which it considered to be adequate. In the application, Imperial presented the results of a study carried out to determine the maximum ground level concentrations of sulphur dioxide that would result from the processing of 5.0 MMscfd of Golden Spike D-1 gas of 2.02 mole per cent hydrogen sulphide and 2.0 MMscfd of Basal Quartz gas of 0.04 mole per cent hydrogen sulphide. The acid gases removed from the inlet stream would be burned in the new six-inch diameter 200-foot flare stack with the addition of a minimum of 80 Mcfd of fuel gas. The flare stack would be equipped with a forced air enclosed incinerator tip to ensure complete combustion and reduce the visibility of the flare. Imperial calculated the maximum ground level concentration of sulphur dioxide to be 0.1919 ppm using the Pasquill method for elevated flares. This concentration is slightly below the Provincial standard of 0.20 ppm calculated concentration at ground level.

Imperial also evaluated the use of low pressure D-2 and D-3 solution gas from a battery adjacent to the plant as flare fuel when it is available. This gas is slightly sour and would be available at rates up to 300 Mcfd and at an average rate of 150 Mcfd. The maximum sulphur dioxide concentration at ground level was calculated by Imperial to be 0.1887 ppm when using the low pressure solution gas as fuel.

While Imperial proposed to use the new 200-foot stack to flare acid gas it also proposed that the existing 65-foot stack would be used to flare untreated D-1 or Basal Quartz Blairmore A gas during plant start-ups and emergencies. Imperial submitted calculations using the Pasquill method which indicated a maximum ground level sulphur dioxide concentration of 0.10 ppm due to the flaring of 5.0 MMcfd of D-1 gas and 2.0 MMcfd of Basal Quartz gas at the 65-foot stack.

In order to ensure that the standards would be met, Imperial stated that the sulphur dioxide air quality monitoring network in the plant vicinity would be expanded from the present requirement of one continuous monitor in operation for one month each year to one continuous monitor in operation for six months each year, and the number of exposure cylinders would be increased from 9 to 12 stations. Imperial stated that the locations of the additional exposure cylinders would be subject to the approval of the Department.

.2 Views of the Interveners

Several of the interveners questioned the accuracy of the Pasquill method for calculating ground level concentrations resulting from elevated flares. Dr. Hage et al stated that the theory of plume dispersal has not advanced to the point where accurate results can be determined, especially with the uncertainties of non-uniform terrain and forested areas and stated that precision to four figures when indicating ground level concentrations of sulphur dioxide is not justified. Dr. Hage submitted the results of ground level sulphur dioxide concentration calculations carried out using calculation methods other than the Pasquill method used in Alberta. His calculations indicated that concentrations of 0.4 ppm under fumigation conditions with no wind and 0.2 to 0.3 ppm under fumigation conditions with light winds could result from the proposed operation. These concentrations exceed the Alberta standards. Dr. Hage stated that available meterological data indicates that fumigation conditions could be expected on one or more occasions during each warm season month. Dr. Hage concluded by saying that there are important uncertainties involved in extrapolating the Pasquill formula to areas such as Golden Spike and that other formulas yield different results - some of which exceed the standards.

Mr. McDonald, in his intervention, stated that variations in winds, temperatures, inversions, and ground cover cannot be anticipated in theoretical formulas for plume dispersal. Many of the other interveners also made reference to the dispersion formula with particular regard to its deficiency in predicting fumigation effects and the effects of topography.

The Sinclairs, in their submission, stated that the erection of a 200-foot stack would not reduce the total amount of sulphur dioxide emitted. They stated that the practice of using higher stacks appears to reduce ground level concentrations but that early morning fumigations or short periods of high concentrations may still occur. They expressed concern that there have been no actual tests of the completeness of combustion in the flare stack as claimed by the manufacturer. They stated that the monitoring system appears inadequate in that emissions other than hydrogen sulphide and sulphur dioxide are not monitored even though they may be harmful. The Sinclairs concluded the industry must take the cost of pollution control upon itself as part of the annual operating cost.

The submission of Mrs. Goebel and Mr. Adolph stated that Imperial's proposal for monitoring was unacceptable and that the number of exposure cyclinder stations should be increased to at least three times the present number. They also stated that an independent supervisory agency should be used to conduct the continuous monitoring.

Dr. Hage et al objected to the type of monitors used by Imperial and the Government, as well as the frequency of monitoring, location and arrangements for monitoring. They stated that the monitors record only monthly averages of sulphur dioxide and hydrogen sulphide and did not show the daily variations. They concluded that because of this, it was unlikely that the Provincial standards would be effectively adhered to. They also expressed concern that mercaptans were not monitored. Dr. Hage et al stated that monitoring should show daily levels and that the proposed increase in continuous monitoring to six months per year would be satisfactory if the six-month period was spread out during the year and consisted of individual days in the vicinity of the plant. They stated that there was a lack of confidence in the monitoring results since Imperial conducts the exposure cylinder monitoring itself and suggested that the Government should fully control all monitoring.

The submission of Mr. McDonald stated that the present arrangement of monitoring was irrational and inadequate in that no exposure cylinders were located east of the plant even though the predominant wind directions are from the west and north-west. Mr. McDonald questioned the continuous monitoring results since the trailer is used for only one month per year and is located south-east from the plant while the winds are generally from the south-east during the winter months. He concluded that there was reasonable doubt that Imperial can assure that the Provincial standards would be met.

8.3 Position of the Department

It is the position of the Department that the stack design formula in use in the Province provides adequate assurance that sulphur dioxide concentrations in excess of the standard will not occur. The Department recognizes that other calculation methods are available but it has adopted its modification of the Pasquill method for use in the Province. Experience in the Province to date indicates that this method usually results in calculated concentrations higher than those observed in the field, thus providing a margin of safety beyond that reflected in the standards.

Respecting the concern expressed by several of the interveners that the flare stack may not provide complete combustion of the acid gas, the Department is of the view that since the flare stack would be equipped with a forced air incinerator tip, essentially complete combustion would be achieved.

The Department shares the concern of the interveners that the existing monitoring system would not be adequate. However, the Department is of the view that the proposal to require 12 exposure cylinders and one continuous monitor for six months of each year would be satisfactory. This much monitoring goes somewhat beyond the Department's normal requirements of eight exposure cylinder stations to detect monthly average total sulphation and hydrogen sulphide levels in the ambient air and one continuous monitor to be operated three months per year for this size of facility. The Department would require that the additional exposure stations be located to the north-east of the plant at locations approved by the Department. The continuous monitoring would initially be carried out to the east of the plant at a location approved by the Department and would be required for at least two separate periods during each year.

The Department is of the view that it would be economically impractical for the Government to carry out all monitoring in the Province. The Department does carry out surveillance of company monitoring operations and intends to commence its own exposure cylinder monitoring in the Golden Spike area by installing two exposure cylinder stations. The Department also proposes to conduct a one month odour and continuous monitoring survey in the area each year.

8.4 Views of the Board

The Board is of the view that the 200-foot acid gas flare stack and the 65-foot emergency flare stack would be adequate to ensure compliance with the Provincial standards. Calculations by Board staff using the Pasquill method indicate a maximum half-hour average sulphur dioxide concentration of 0.12 ppm at ground level and 0.16 ppm at tree top level due to the proposed emissions from the 200-foot flare stack and maximum half-hour average concentrations of 0.13 ppm at ground level and 0.20 ppm at tree top level due to emissions from the 65-foot flare stack during a plant start-up or emergency. All concentrations are within the Provincial half-hour standard of 0.20 ppm.

In regard to the question of ensuring complete combustion of the acid gas, the Board is of the opinion that the proposed stack with a forced air incinerator tip would provide reasonable assurance that combustion would be complete. However, the Board calculated the size of stack that would be required if, instead of flaring, the acid gas were incinerated in an enclosed burner at the base of the stack and the resultant flue gas exhausted to the atmosphere through a stack. The Board calculates that a stack 1.3 feet in diameter and 200 feet in height would be required rather than the proposed 200-foot six-inch diameter flare stack. The Board recognizes that the incinerator and stack would be more expensive than Imperial's estimate of $50,000 for the proposed flare stack and estimates this facility would cost approximately $80,000. The incineration alternative is more costly but would provide the advantages of absolutely ensuring complete combustion, eliminating a visible flame, reducing the likelihood of a noise problem and conserving the gas that would otherwise be required for flare fuel. In the Board's view these advantages would out weigh the additional costs and consequently Imperial should be required to install the incinerator and stack instead of the proposed flare stack.

The Board is of the view that 12 exposure cylinders and six months of continuous monitoring per year would be adequate for the general plant area. The Board believes that the additional exposure cylinder monitoring should be carried out to the northeast of the plant where coverage has been inadequate in the past. Also, the additional continuous monitoring should initially be carried out approximately one mile east of the plant where the Board's calculations indicate maximum sulphur dioxide concentrations would occur.

The Board agrees with the Department that it would be impractical for the Government to carry out all necessary monitoring in the Province. However, the Board concurs with many of the interveners that Government monitoring in the area, for surveillance purposes, should be increased. The Board understands that the Department intends such an increase in monitoring and recommends that the results of the monitoring be made available to the interveners at the subject hearing.

9. THE USE OF SOUR FUEL GAS FOR THE ACID GAS FLARE

9.1 Views of Imperial

Imperial stated that at the Golden Spike Plant there is available up to 300 Mcfd of solution gas from a low pressure separator handling oil production from the Golden Spike D-2 A and D-3 B Pools. Imperial stated that the rate of production of this gas averages 150 Mcfd. The gas is now being used to provide a fraction of the fuel gas requirements for the plant hot oil heater and results in the emission of up to 0.62 long tons of sulphur dioxide per day from this source. Imperial proposes to use the gas as flare stack fuel as a substitute for the 80 Mcfd of sweet gas that would otherwise be required.

Imperial stated that it had investigated the possibility of compressing this gas to the inlet pressure of the scrubbing plant to make the gas available for injection purposes. This would make available 150 Mcfd less the 80 Mcfd required for flare stack fuel gas. Imperial estimated the capital and annual operating cost of the required compressor and piping to be $67,000 and $3,340 respectively. Imperial said that the additional residue gas would have a value of 20 cents per thousand cubic feet or $5,110 per year. This would result in a payout of in excess of 30 years and in Imperial's view this alternative would not be economically attractive.

9.2 Views of the Interveners

T. J. Trimble, and other interveners, submitted that the sour D-2 A and D-3 B gas should be conserved by sweetening. Mr. Trimble stated that a more realistic gas price of 30 cents per thousand cubic feet would yield a return of approximately five per cent making the conservation of this gas economically reasonable.

Views of the Board

The Board examined the economics of conserving the sour
A and D-3 B solution gas by compressing it from the plant inlet
ssure of 20 pounds per square inch to the amine plant pressure
375 pounds per square inch. Since the Board believes that Imperial
uld incinerate rather than flare the acid gas, the Board based
evaluation on the total volume of gas that would be available,
ch is expected to average 150 Mcfd. The Board calculated that
0-horsepower compressor would be required and estimated its
ital and annual operating costs to be $45,000 and $3,200, respect-
ly. The Board recognizes that Imperial would not be selling this
but injecting it. However, the Board has assigned a sales
ue to the gas on the basis that if the gas was not conserved it
ld probably be necessary to meet the equivalent injection require-
ts with some other residue gas supply which would probably be
chased. The Board assumed a residue gas value of 30 cents per
in 1974 escalating to 57 cents per Mcf in 1988. The future
values used by the Board reflect the Board's expectations
pecting minimum gas prices over this period having regard for
reased demand for energy. The Board's analysis indicated that
compressor installation would payout in some four years and
ld a discounted rate of return in excess of 30 per cent before
es. The Board concludes that conservation of this gas would be
nomic and should be required.

THE VIABILITY OF ALTERNATIVES OPEN TO IMPERIAL

The Board has studied several alternatives to that
posed by Imperial for disposal of the acid gas. These alter-
tives are discussed herein in some detail. In considering the
posed scheme and any alternatives to it, the Board holds the
ew that Imperial must meet all environmental standards regard-
ss of cost. As discussed earlier in the report, the Board
lieves that the facilities proposed by Imperial could be oper-
ed within Provincial standards. The alternatives to that pro-
sed by Imperial for disposal of the acid gas go beyond the requir-
nts of the Provincial environmental standards. The Board has,
erefore, considered the economics of each of these alternatives
d would not be prepared to require further resource conservation
less it was reasonably economic to do so.

The Board considers the alternatives open to Imperial
be:

(a) processing the acid gas stream for the recovery of sulphur to reduce the sulphur dioxide emission rate,

(b) injecting the sour D-1 A and Blairmore A gas to the gas cap of the D-3 A oil reservoir to eliminate sulphur dioxide emissions,

(c) injecting the acid gases removed from the D-1 A and Blairmore A gas to other zones in the general area to eliminate sulphur dioxide emissions,

(d) supplying the injection requirements with only Blairmore A or other relatively sweet gas to reduce sulphur dioxide emission rates,

(e) supplying the additional injection requirements with purchased sweet gas from elsewhere in the Province to eliminate sulphur dioxide emissions, and

(f) injecting lesser volumes of gas and more solvent so that production of the sour D-1 A gas would not be required and the sulphur dioxide emissions would thus be reduced.

10.1 The Recovery of Sulphur

10.11 Views of Imperial

Imperial submitted an economic evaluation of the installation of Claus sulphur recovery facilities. It estimated the capital cost to be $222,000, annual operating costs to be $14,000, and annual revenue to be $6,300 based on a sulphur price of $5 per long ton. Imperial concluded that sulphur recovery would not be economically feasible since the revenue derived from the sale of the recovered sulphur would be insufficient to cover even the operating costs.

In testimony at the hearing, Imperial stated that, to its knowledge, there has never been a sulphur recovery plant designed for as little as four long tons per day, and that one of the technical problems associated with a plant of this size would be whether the plant could be operated satisfactorily at throughput rates sufficiently below the design maximum rate to meet requirements. Claus sulphur recovery plants are normally not capable of operating at rates below 50 per cent of design throughput. It would be necessary for the plant to be capable of operation at a greater degree of throughput reduction than 50 per cent in this instance because of the eventual decline in sour gas productivity.

In reply to questioning, Imperial stated that the iron sponge process was considered as an alternative to the Claus process but was found to be unacceptable since it is practical only for very small volumes and very low concentrations of hydrogen sulphide.

10.12 Views of the Interveners

Dr. Hage et al stated that the economic analysis by Imperial of the installation of sulphur recovery facilities was not valid because it did not recognize the resultant saving of the cost of the 200-foot stack, possible future increases in sulphur prices, or the possible cost of litigation in the future. They argued that the annual operating loss projected by Imperial of some $7,700 was small compared to the possible harmful effects that might result from sulphur dioxide emissions and that apparently Imperial was not concerned about the environmental effects of these emissions. They also stated that Imperial's capital cost estimate of $222,000 was too high and quoted costs from literature of some $50,000 to $75,000.

Mr. Lee stated, on behalf of Unifarm, a belief that iron sponge units could be installed which would be suitable for a plant of this size. He acknowledged that this would be at additional cost to Imperial.

10.13 Views of the Board

The Board analysed the economics of recovering sulphur at the Golden Spike Plant at the proposed maximum sulphur throughput rate of approximately four long tons per day. The Board estimated that the capital cost of the sulphur recovery facility would be approximately $150,000 and that its annual operating cost would be approximately $12,000. From Imperial's estimate of D-1 gas production and assuming a 90 per cent sulphur recovery efficiency, the Board calculated a maximum annual sulphur production of 680 long tons in 1974, the peak year of sulphur production. If all of the production could be sold at an optimistic price of $9.00 per long ton the revenue from sulphur sales would be approximately $6,100 in 1974. It is not likely that all of the production could be sold at such an average price.

The Board notes that if sulphur recovery facilities were installed a capital cost saving would result since the acid gas disposal incinerator and the stack would no longer be required. However, since complete recovery of sulphur is not technically feasible using the Claus process, this cost saving would be offset by the cost of constructing a smaller incinerator stack to vent the unrecovered sulphur, from the Claus plant, as sulphur dioxide at rates up to 0.83 long tons of sulphur dioxide per day. The Board calculates that an incinerator stack 35 feet in height would be required and estimates its capital cost to be $30,000.

The Board evaluated the cost of sulphur recovery for the period 1974 to 1986 inclusive using its best estimate of sulphur prices and sulphur sales volumes and Imperial's D-1 gas production forecast. The Board's evaluation indicated that the sulphur recovery facilities would yield a net loss discounted at 10 per cent per year of approximately $225,000. Taking the stack savings into account the calculated net loss would be $175,000. This evaluation gave no recognition to the throughput reduction problem referred to by Imperial.

The Board investigated sulphur removal using other than the Claus process. This investigation indicated that the Claus process is the closest to being economic. The applicability of the iron sponge process is limited to low volume gas streams containing low concentrations of hydrogen sulphide. Literature indicates that it cannot be practically applied to remove more than 500 pounds per day of sulphur from sour gas streams. It would, therefore, be impractical for this particular situation and, in any event, could create a different form of pollution problem.

The Board recognizes that if other sources of sour gas in the area were produced and were sweetened at the plant for injection purposes, the economics of sulphur recovery would improve due to economics of scale and the higher sulphur production rate. The Board concludes, however, that insufficient additional sour gas would be available in the area to make sulphur recovery economic. It notes further that if sufficient additional sour gas were available the portion of unrecovered sulphur emitted to the atmosphere would also increase although it would remain less than the amount proposed by Imperial.

On the basis of its studies and considerations of the matter, as summarized in the foregoing, the Board concludes that the recovery of sulphur by Imperial, even if technically feasible, would not be economic and in fact would represent a total net cost to Imperial of several hundred thousand dollars. Consequently the Board is not prepared to require sulphur recovery.

10.2 Injection of Sour Gas to the Gas Cap

10.21 Views of Imperial

Imperial stated that the injection of sour gas to the gas cap of the D-3 A Pool would have no immediate effect on oil production. It stated, however, that since the fluids now contained in the pool are sweet, once the oil zone was depleted so that the gas could be produced, the injected sour gas would then require scrubbing on a larger scale than is now proposed.

10.22 Views of the Interveners

The Sinclairs suggested that if the sour gas were injected to the gas cap now, advances in technology could provide better techniques for sulphur recovery at the time that the oil zone was depleted.

10.23 Views of the Board

The Board has examined the feasibility of injecting the sour D-1 A and Blairmore A gas into the gas cap of the D-3 A Pool without sweetening. The Board calculated that this would involve the injection of approximately 0.2 billion cubic feet (Bcf) of hydrogen sulphide into the D-3 A Pool. At the termination of the solvent flood scheme the Board estimates that the D-3 A Pool would contain approximately 250 Bcf of injected and solution gas which could then be produced. If the sour gas were injected, the produced gas would have an average hydrogen sulphide concentration of approximately 0.08 per cent, too high to meet pipeline specifications, and would therefore require sweetening. If the gas was produced at the rate of 1.0 MMcfd per 7.3 Bcf of reserves, the average daily rate would be approximately 35 MMcfd. The existing treating facilities, apparently sized for [illegible] MMcfd, would probably not be capable of processing this much gas and new facilities would therefore be required. The Board estimates he capital cost of the required treating plant, if installed day, would be approximately $200,000. After the gas is treated he resultant acid gas stream would require disposal and could resent problems similar to those now being encountered.

In addition to the above economic considerations, the oard believes that several technical problems could be encount- red if the sour gas is injected to the D-3 A gas cap. For example, quipment problems could result due to the corrosive nature of the our gas. This problem would necessitate changes to injection ells and equipment, further increasing costs.

Based on its economic analysis and bearing in mind that his alternative would only defer to the future the matter of isposing of the acid gas, the Board is of the view that this lternative is less attractive from an overall economic and nvironmental viewpoint than is sulphur recovery and consequently hould not be required.

0.3 The Injection of Acid Gas to Other Zones in the General Area

10.31 Views of Imperial

Imperial considered injecting the mixture of hydrogen sulphide, carbon dioxide and water from the scrubbing plant to an underground formation in the area of the Golden Spike plant. It ruled out this alternative because of the corrosive nature of the wet acid gas at the high pressures necessary for injection. Imperial stated that although it is technically feasible to do this, it felt that the estimated capital cost of some $333,000 and the potential hazards to operating personnel and the environment were too great.

10.32 Views of the Interveners

Many of the interveners raised the possibility of injecting acid gas to an underground formation other than the D-3 A Pool but none presented evidence related thereto.

10.33 Views of the Board

The Board examined the possibility of injecting the acid gas stream to an underground formation. Calculations by Board staff indicate that injection equipment would have to be provided to handle up to 280 Mcfd of acid gas. Assuming a suitable underground reservoir could be developed for this purpose, the Board calculates the compression capacity required to be approximately 100 horsepower which would cost approximately $55,000 for the compressor equipment alone. Other costs would be required for the pipeline necessary to carry the gas to the injection well and the injection well itself. The Board estimates these additional costs would be a minimum of $100,000. This alternative would also present safety problems associated with compressing and transmitting high pressure very sour gas. Considering the cost of this alternative, which the Board estimates to be equal to or greater than for sulphur recovery, the uncertainties associated with finding a suitable underground reservoir, and the inherent safety problems, the Board is of the view that acid gas injection is less attractive than sulphur recovery and should not be required.

10.4 The Production of Only Blairmore A or Other Relatively Sweet Gas and Maintaining the Proposed Throughput Level

10.41 Views of Imperial

Imperial stated that it intends to purchase as much of the slightly sour Blairmore A gas as the single producing well can supply and that the remainder of its total requirement would be made up of sour D-1 A gas. Imperial noted that the remaining recoverable reserves in the Blairmore A pool are estimated to be some three Bcf, and that all of the gas presently being produced from the pool goes to the Golden Spike plant.

In reply to questioning, Imperial stated that it believed that the owners had investigated the possibility of increasing the deliverability of the Blairmore A Pool through further drilling but that any increased deliverability would increase the rate of depletion of these reserves. Imperial stated that it has conducted geological studies in the Golden Spike and Leduc Areas over the past ten years in attempts to find additional gas specifically for injection purposes but that it has been unsuccessful in finding any commercial volumes. Imperial stated that the Golden Spike Viking Pool had been depleted in the early stages of the enhanced recovery scheme and that it was not aware of any new Viking pools in the field.

Imperial's position was that there was not an altervative source of sweet gas available to permit shutting in the D-1 A Pool.

10.42 Views of the Interveners

The interveners did not specifically present views on the issue of the production of only Blairmore A gas or other sources of relatively sweet gas for injection purposes so that the proposed processing plant throughput level could be maintained.

10.43 Views of the Board

The Board reviewed the status of the Blairmore A Pool, the Blairmore B Pool, the Viking Pool and other pools in the Golden Spike Field to determine whether relatively sweet gas would be available in sufficient supply to eliminate the need for gas from the sour D-1 A Pool. Although the Board's study does not agree in detail with the information supplied by Imperial, the Board concurs with the Imperial view that very little sweet gas is available in the area. The gas that is available is not in sufficient supply to completely replace the proposed production of gas from the D-1 A Pool. In any event, the Board is of the view that, even if a large reserve of sweet lightly sour gas was available in the area, it might not be nd conservation to abandon the D-1 A Pool and supply the ction requirements from another source of gas.

The Board notes that Imperial proposes to supply as h of its requirements as possible with gas from the Blairmore ool to minimize the production of the more sour gas from the A Pool. The Board agrees that this approach is appropriate.

The Use of Additional Volumes of Sweet Gas From Elsewhere in the Province

10.51 Views of Imperial

Imperial stated it is purchasing as much gas as possible m all other sources at the present time and that it is investi- ing the installation of additional pipe lines from such areas Lost Point Lake and Judy Creek in order to transport gas to Golden Spike Area to maintain and increase oil production rates. erial noted that its present gas supply was inadequate to main- n production rates and that, during some months, it has been essary to decrease oil production rates considerably because this situation in order to maintain proper crude oil reservoir formance.

In reply to questioning, Imperial stated that it had vestigated the possibility of bringing surplus gas from the neson Field to the plant but discarded this possibility as practical. Imperial stated that there are gas consumers on e present sweet gas pipe line between the Acheson Plant and lden Spike Plant so that the slightly sour Acheson field gas uld not be transported in the existing line.

10.52 Views of the Interveners

T. J. Trimble and other interveners stated that surplus eet gas from the Acheson Field, 11 miles from the Golden Spike ant, should be utilized for injection purposes. He stated that is gas would be suitable for pressure maintenance purposes.

10.53 Views of the Board

The Board has considered the alternative of using other pplies of sweet gas for injection purposes instead of using the s from the D-1 A Pool as proposed in the application. Gas from outside source would have to be purchased. The Board assumed e price of the purchased gas would be 30 cents per Mcf in 1974 calating to about 53 cents per Mcf in 1986. Using the gas oduction schedule submitted by Imperial for the D-1 A Pool, the rd calculated a cost in 1974 of $300,000 to purchase sweet gas replace the forecast sour D-1 A gas requirements. This cost uld be reduced slightly by savings in treating plant operating sts. Over the period 1974 to 1986 inclusive the Board calculated e discounted net cost of this alternative to be approximately two llion dollars assuming an annual discount rate of ten per cent.

This alternative is not attractive from an economic standpoint and should not be required.

10.6 The Injection of Lesser Volumes of Gas and More Solvent

10.61 Views of Imperial and the Interveners

Neither Imperial nor the interveners commented on the possibility of injecting lesser volumes of gas and more solvent so that sour D-1 A gas production and injection would not be necessary.

10.62 Views of the Board

The Board considered the possibility of requiring an increase in the injection rate of solvent so that gas injection rates could be decreased. The Board calculates that solvent injection rates would have to be increased approximately 1500 barrels per day for each one million cubic feet per day reduction in gas injection rates. Since it would be necessary to purchase the extra solvent, the Board calculates the cost of this alternative in 1974 would be approximately $3,000,000.

This alternative is not as attractive as many of the others and consequently should not be considered.

10.7 Overall Board Views Respecting Alternatives Available to Imperial

Having reviewed all apparent alternatives to the Imperial proposal, the Board considers none to be economically reasonable and consequently is not prepared to require an alternate method of disposal of the acid gas from the Golden Spike gas processing plant.

11. ENVIRONMENTAL PROBLEMS RELATED TO ASPECTS OF THE OPERATION OTHER THAN THE FACILITIES FOR FLARING OF HYDROGEN SULPHIDE

11.1 Views of Imperial

Imperial submitted that it was in the process of upgrading the safety and reliability features of the Golden Spike Gas Plant at considerable expense in order that its own operating personnel as well as the environment would be better protected. The upgrading program includes installing a new emergency system, installing new drain systems in the plant, fireproofing, installing explosion meter detectors, installing hydrogen sulphide detectors, electrical system upgrading, and upgrading the cooling systems and fire-fighting systems.

In reply to questioning, Imperial stated that a crude oil storage tank on the plant site with approximately five thousand barrels of capacity is used for temporary storage when mps are shut down for routine maintenance or in the event of eakdowns. It indicated that since the last stage of separation e maintained within one ounce of atmospheric pressure there uld be no problem with venting of tank vapours to the atmosphere. perial also stated that it was in the process of modifying the ergency flare system in the plant so that all relief valves uld be tied into the flare system.

Imperial stated that its medical staff has conducted ise level surveys at the plant site and that the results showed at, except for inside some of the buildings, the noise levels re less than ninety-five decibels and that at the edge of the ant site, the level was some fifty-seven decibels. Imperial ated that surveys were not conducted at the plant property undaries but it anticipated that the levels at the boundaries uld be lower. It stated that surveys could be conducted to tain noise level readings at the road allowance adjacent to e plant. Following the hearing Imperial carried out a noise rvey and reported the results to the Board and the interveners.

Imperial noted at the hearing that if a reduction in ise levels was necessary, acoustical engineering consultants ould be hired to determine the most effective method of doing his.

The applicant stated that flaring of gases other than he acid gas would not normally occur at the plant except in the vent of upsets or routine maintenance, and stated that emergency laring would be done through the existing 65-foot stack. It tated that significant night illumination would rarely occur ince flaring from the 65-foot emergency flare stack would be nfrequent. It expected illumination from the proposed 200-foot cid gas flare stack to be slight because of the small volume urned and the efficiency of the forced air incinerator tip. The nly other illumination from the plant would be from flare pilots nd aircraft lights on the stacks.

Imperial stated that it was carrying out engineering esigns, including the automatic control of wells, which would revent the recurrence of oil spills in the area.

1.2 Views of the Interveners

Several of the interveners expressed their concern egarding the possible increase of obnoxious odours from the lant, illumination from flaring operations at night and noise enerated from the flare stacks and compressors if the application was approved.

Mr. A. Miller expressed his concern that flaring, hich is especially noticeable in winter, occurs continuously t many wells in the area and felt that this gas should be onserved.

The submission of Mrs. Goebel and Mr. Adolph stated hat sulphur dioxide and hydrogen sulphide were the cause of orrosion in wire fencing, metal buildings and equipment, stone and brickwork, and deterioration of clothing. It stated that hydrogen sulphide affected milk production from dairy cattle and discoloured and deteriorated painted surfaces. The interveners contended that the operation of gas plants in the area of Pincher Creek, Nevis and Golden Spike was the cause of abortions and abnormalities in beef and dairy cattle.

Several interveners submitted that the height of the new stack would make it, as well as the emissions from it, visible from a greater distance than the present stack. They also expressed concern that the noise levels from the stack would increase.

The submission of Dr. Hage et al stated that Imperial could not guarantee that the plant would not be a source of offensive odours, and noted that these odours are presently detected in the area on occasion. It stated that The Clean Air Act does not explain what offensive odours are and does not explain how an individual might have the Director of Pollution Control witness or experience such odours.

Dr. Ironside stated that Imperial could not guarantee that there will be no pollution by odour, noise, or any other form from the plant. He noted that odours are already detected at a distance of one and one-half miles from the plant, particularly on cold winter days and under other atmospheric conditions.

The submission of Mr. and Mrs. Sinclair stated that corrosion from sulphur dioxide is even more severe than that of a marine environment and that normal corrosion rates are accelerated in the presence of sulphur dioxide. They expressed their concern that any damage costs resulting from the operation of the plant would be borne by the residents in the area.

11.3 Views of the Board

The Board has carefully considered the evidence presented by the interveners with respect to the overall conditions of the environment in the Golden Spike area and, after consultation with Board field staff, finds that:

1. Air quality monitoring in the area to date indicates satisfactory operation with respect to Provincial Air Quality Standards, but, an intensification of monitoring is desirable and, as discussed herein, will be required,

2. Odours from the plant area have occurred in the past and should be eliminated. The Board is of the view that the upgrading proposed at the plant, elimination of the use of sour fuel gas in the process heater and installation of the higher stack would reduce the intensity and occurrence of odours. A probable additional source of odours is the plant flare pit to which relief valves on the plant inlet separators are vented. The Board requires that open tanks be installed in accordance with section 8.031 of the Oil and Gas Conservation Regulations so that these fluids would not be directed to the pit in an emergency. The Board believes that further major modifications

the plant and field facilities are not warranted at this time will require Imperial to carry out a plant emission study to ntify sources of flaring and odours and report its findings the Board by July 31, 1974. This study should present a tailed report for the period July 1, 1973 to June 30, 1974 of

(a) all sources of gas flaring at the plant and in the field, flaring occurrences and volumes from each source during the period, and a description of any action taken or proposed to minimize flaring occurrences,

(b) all occurrences of black smoke and a description of any action taken or proposed to eliminate smoke occurrences, and

(c) all occurrences of emissions from the plant, however minor, other than those from the emergency flare stack, acid gas flare stack or incinerator stack, which could cause odours in the vicinity of the plant, and a description of action taken or proposed to eliminate these emissions.

3. Imperial's proposed upgrading of the waste water ontrol facilities appears to be satisfactory.

4. In view of the Board's plan to require disposal of cid gases through an enclosed incinerator and stack, illumintion from night flaring should be infrequent and only occur ue to occasional equipment maintenance and emergencies.

5. The noise survey submitted by Imperial indicated noise evel readings as high as 65 dBA at the plant boundary and as igh as 45.5 dBA adjacent to the Whispering Pines subdivision. oard noise control guidelines issued June 18, 1973 by Interim irective No. ID 73-1 permit maximum day time noise levels of 65 BA and night time noise levels of 50 dBA measured at a distance 10 feet from any occupied permanent residence. It appears hat the noise levels in the Golden Spike plant area would be at cceptable levels but the Board believes that further noise urveys carried out in accordance with ID 73-1 would be desirable. he surveys should be carried out while the plant is operating maximum load after the new incinerator and stack commence peration.

. DECISION

Since none of the alternatives are attractive or necesary to meet the Provincial standards, the Board grants that part the application to increase the maximum hydrogen sulphide inlet ate to 110 Mcfd and the maximum sulphur dioxide emission rate to 28 long tons per day subject to the conditions that:

1. The acid gas stream be incinerated at ground level and vented to the atmosphere through an incinerator stack, the design of which would be subject to the approval of the Board and the Department.

2. Imperial's air quality monitoring requirements be increased to 12 exposure cylinder stations and one continuous monitor to be operated for six months during at least two separate periods of each year.

3. The sour D-2 A and D-3 B solution gas be conserved by compression to the amine treating plant.

4. Imperial direct all relief valves on separators, treaters and other pressure vessels containing oil within the plant to an open tank or tanks in accordance with section 8.031 of the Oil and Gas Conservation Regulations.

5. Imperial undertake a plant emission study and report its findings to the Board by July 31, 1974.

6. Imperial undertake a further noise survey in the area under the direction of Board staff.

Amendment of Approval No. 1531 is being issued concurrently with this decision.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier, P. Eng.
Chairman

Dated at Calgary, Alberta
July 25, 1973

ATTACHMENT 1 TO DECISION 73-

APPLICATION NO. 6823

LIST OF INTERVENERS AS OF APRIL 5, 1973

EXHIBIT NO.	NAME OF INTERVENER	DATE OF INTERVENTION
1	Rob Abraham	March 27, 1973
2	Mrs. Roberta E. Abraham	February 26, 1973
3	Mrs. Albert Adam	February 26, 1973
4	Mr. J. Adolf	February 17, 1973
5	Mr. Walter H. Adolf	February 27, 1973
6	Mr. & Mrs. Walter Androff	February 20, 1973
7	J. A. Banister	March 29, 1973
8	E. H. Bauer et al	February 16, 1973
9	Mr. Ronn Bence	February 23, 1973
10	Mr. Melvyn A. Binder, Esq.	March 9, 1973
11	Mr. & Mrs. Jens Boje	February 23, 1973
12	Mrs. Sig Boje	February 22, 1973
13	Mr. Paul Brutkreutz	February 28, 1973
14	Mr. & Mrs. E. J. Burroughs	March 12, 1973
15	Mr. T. R. Bryce	February 27, 1973
16	N. Cherwonick	
17	W. O. Congdon	February 26, 1973
18	Mr. A. H. Crawford	February 27, 1973
19	Mr. & Mrs. R. C. Davis & Mr. H. Taylor	March 29, 1973*
20	Mr. Melvin Dettmer	February 17, 1973
21	Mr. Bert Diedrich	February 28, 1973
22	Mr. Joseph Doz	March 29, 1973
23	Mr. Ronald Esch	February 23, 1973
24	Mr. Neil Fiertel	February 22, 1973
25	Mr. & Mrs. L. G. Folkins	February 20, 1973
26	Mr. & Mrs. Garth Ford	April 3, 1973*
27	Mrs. M. A. Forester	March 29, 1973*
28	Mr. R. L. Foster	March 1, 1973
29	Mr. Edward Frank Sr.	
30	Maxine E. Frank & Edward A. Frank	February 19, 1973
31	Mr. Edwin A. Frank	
32	L. Frederiksen	February 27, 1973
33	Mr. Gorndon H. Gabel	February 21, 1973
34	R. C. Gabelmann	
35	Mr. Art Gehlert	
36	Mr. & Mrs. E. Gehlert	February 19, 1973
37	Mr. & Mrs. T. E. Gehlert	February 15, 1973
38	Mr. Charlie Giese	February 23, 1973
39	Mr. Harvey E. Giese	February 22, 1973
40	Mr. Rudolph Giese	February 22, 1973
41	B. R. Gilbert & Leo Ferguson	
42	Mr. Emil Gitzel	February 23, 1973
43	Mr. Marvin Gitzel	February 20, 1973
44	Mr. & Mrs. Roy Gitzel	February 21, 1973
45	Mr. & Mrs. G. F. Geobel	February 21, 1973
46	Mrs. Irene Goebel et al (brief)	March 29 & 30, 1973
47	Mr. Tom Gray	February 24, 1973
48	K. D. Hage	February 26, 1973
49	K. D. Hage et al (brief)	March 29, 1973

Mrs. E. J. Harder	February 14, 1973
[illegible] L. Hardy	February 19, 1973
L. Haymon et al	February 19, 1973
Mr. & Mrs. Arthur E. Hennig	February 19, 1973
Mr. Ed E. Hennig	February 20, 1973
N. L. Hennig	February 16, 1973
Milo & Faith Hill	February 19, 1973
Dr. Leila Howell	March 29, 1973
Dr. Leila Howell	February 19, 1973
Dr. R. G. Ironside	February 21, 1973
Dr. R. G. Ironside	February 26, 1973
Reply to Dr. Ironside	February 28, 1973
Mrs. Alice Mary Jamieson	February 13, 1973
Mr. Werner Jappson	March 5, 1973
Mr. & Mrs. James G. Kennedy	March 6, 1973
Mr. L. Klein	February 26, 1973
Mr. Charles Knebel	February 19, 1973
Valentine & Emilie Knebel	February 19, 1973
John and Sharon Knol	February 19, 1973
Mr. Anthony Lambert	March 2, 1973
Mr. & Mrs. Peter Marchuk	March 15, 1973
Mrs. Barbara Dawn Martin	February 21, 1973
Mr. W. L. & Judy McFarlen	March 4, 1973
Mr. & Mrs. J. McLaughlin	February 26, 1973
Mr. Merril McDonald	February 23, 1973
Mr. Merril McDonald (brief)	March 28, 1973
Mr. Werner Merlo	March 1, 1973
F. W. Michna	February 19, 1973
A. K. Miller	March 1, 1973
M. Mohan	February 22, 1973
Susan B. Mohan	February 19, 1973
James & Florence Moir	February 28, 1973
R. D. Morin & M. A. Morin	March 30, 1973
M. Nonaz	February 20, 1973
Mr. Keith Oberle	March 29, 1973
Ellis G. Oberle	March 12, 1973
Tom & Laurine Paulson	March 1, 1973
Mr. John Patten	February 26, 1973
Mr. & Mrs. Steve Peregrym	February 21, 1973
Mr. L. Proudfoot	
Egon & Elvisia Quix	February 20, 1973
J. Y. Ramsey	February 28, 1973
Edith & Hans Rasmussen	February 21, 1973
W. Rauschning	February 26, 1973
Mr. & Mrs. P. M. Revel	March 17, 1973
Mr. & Mrs. R. Russ	February 14, 1973
Prem Saigal	February 20, 1973
Mrs. I. M. Scabar	March 16, 1973
L. M. Schopp (Rotation Farms Ltd.)	March 30, 1973*
Albert & Birdur Schultz	February 19, 1973
Mr. Ed Schaepp	February 26, 1973
Mr. George Schaepp	February 23, 1973
Richard Secord	March 24 & 28, 1973
M. Shuster et al	February 28, 1973
Francesco & Biazino Sibbio	February 28, 1973
Mr. & Mrs. R. Sinclair (brief)	February 21 & March 29, 1973

106	Mrs. Gloria Siperko	February 26, 1973
107	Rev. K. F. Steizer	February 20, 1973
108	R. Sturtz	March 23, 1973
109	Mrs. D. Thomson	February 26, 1973
110	Mrs. Jacob Trautman	
111	Leslie L. Trautman	February 21, 1973
112	T. J. Trimble, P. Eng.	March 1, 1973
113	F. L. Ulmer	February 20, 1973
114	Wilfred & Arlene Ulmer	February 20, 1973
115	Unifarm (brief)	March 19, 1973
116	Mr. John Vanthoff	February 22, 1973
117	Sandra Van Stolk	
118	Mr. W. E. Wall	March 1, 1973
119	Mr. & Mrs. U. Werle	
120	Mr. & Mrs. D. Whitlock	March 1, 1973
121	Louie Yethon	
122	David E. Young	March 10, 1973
123	Oscar & Elsa Zaft	February 26, 1973
124	Mr. Robert Zutz	February 26, 1973
125	Petition	February 20, 1973
126	Petition	February 26, 1973

* received after March 30, 1973

ENERGY RESOURCES CONSERVATION BOARD

ADDENDUM TO
Decision 73 - 14
Application No. 6823

INCREASE IN THE MAXIMUM PERMITTED HYDROGEN SULPHIDE INLET RATE AT THE GOLDEN SPIKE GAS PROCESSING PLANT

1. BACKGROUND

Following the hearing of the subject application on April 6, 1973, the Board made its decision with respect thereto, as set out in Decision 73-14, dated July 25, 1973.

In accordance with the requirements of section 38 of The Oil and Gas Conservation Act, the Board, on July 27, 1973 forwarded to the Minister of the Environment a copy of Application No. 6823 for his approval thereof, insofar as it affects matters of the environment. As the Minister's approval of the application was withheld, the Board deferred releasing Decision No. 73-14 until that approval had been given by the Minister. Accordingly, approval of the application by the Board has to date not been granted.

Subsequent to the Board's transmittal of Application No. 6823 to the Minister of the Environment, the Minister met with representatives of Imperial Oil Limited and requested that Imperial review alternative methods of disposing of the acid gas produced at the Golden Spike gas processing plant other than using a flare stack as was proposed in Application No. 6823. Imperial completed its studies on alternative disposal methods and submitted a summary of them to the Board and to the Department of the Environment.

2. SUBMISSION OF IMPERIAL

In its submission (a copy of which is attached) Imperial reviewed six alternatives - two separate sulphur recovery systems, underground gas injection, a sour gas pipeline, an incinerator stack, and a flare stack. Two of the alternatives, the sour gas pipeline and the acid gas injection, are considered to be unsuitable in view of the environmental and safety considerations related to the operation of corrosive high pressure gas systems. With respect to the two sulphur recovery systems Imperial calculated that the high costs of the processes, severe operating problems and high operating costs make them both uneconomic and technically undesirable.

The two other alternatives considered were the flare
ack and the incinerator stack. Imperial calculated that a
0-foot incinerator stack with a 3-foot internal diameter would
required in order to meet the 2,000 ppm dilution requirements
d a 300° Fahrenheit exit temperature to conserve fuel. The cost
the stack is estimated to be $700,000 and the fuel requirements
0 MCFD. Imperial also pointed out that the incinerator would
ve a greater visual impact than would a 200-foot flare stack,
uld not reduce the amount of sulphur emitted to the atmosphere
en compared to the flare stack and would be significantly more
pensive than the flare stack which would cost about $50,000.
th the improvement in flare stack design Imperial also indicated
at the problems of incomplete conversion and luminour flames
ve been eliminated. Therefore Imperial concluded that the flare
ack was the most flexible, reliable and most economic method of
sposing of the acid gas while meeting all the environmental
andards.

VIEWS OF THE BOARD

In view of new data filed by Imperial and the length
elapsed time since the Board made its decision on the subject
lication, the Board believes it appropriate to re-evaluate the
lication under today's economic and technological conditions.

The most significant change in the past three years has
n the rapid escalation of the cost of construction and materials
the increase in the price of natural gas and related products.
example, the Board estimated in 1973 that the cost of a
phur recovery unit to handle the acid gas would be some $150,000.
also estimated that the value of natural gas would be 30 cents
Mcf in 1974 and 57 cents per Mcf in 1988. Currently it esti-
es the sulphur recovery unit would cost $435,000 and current
ural gas prices are in the order of $1.20 per Mcf. While the
t of equipment and the value of products used in the Board's
ginal decision are low compared to today's figures, the relative
ues (particularly if the product prices are considered as
after royalty) remain essentially the same. The Board con-
des that the economics of installing sulphur recovery facilities
ain unfavourable under today's conditions. This is in agree-
t with Imperial's findings.

Injection of the acid gas and the sour gas pipelines
e also rejected by the Board as viable alternatives in view
the high costs, safety and environmental considerations.
hing has occurred to change the Board's views respecting these
ters.

The final alternative reviewed by the Board was the
sibility of substituting an incinerator stack for the flare
ck. In its initial evaluation the Board calculated that an
inerator stack was slightly more expensive to construct than

a flare stack but the advantages of the incinerator stack in eliminating a visible flame and ensuring complete combustion were such that the Board decided that an incinerator stack was preferable to a flare stack. However, with the advances in the design of flare stacks, a flare stack would now be equally able to ensure complete conversion and a non-visible flame. Economically the gap between the cost of constructing an incinerator stack and flare stack has widened to where the cost of an incinerator stack is significantly greater. Additionally the incinerator uses approximately three times as much fuel. The Board thus concludes that the flare stack is more desirable than an incinerator stack from both an economic and a conservation aspect and is comparable on an environmental and technical level. If after installation of a flare stack there is a problem with flame luminosity, the Board will require appropriate upgrading or remedial measures to be taken.

The Board considered whether or not there was a need to reopen the hearing of the application. A review of the earlier decision showed that the only condition which now differs from the situation considered at the original hearing is the relative merit of using a flare stack rather than an incinerator stack for the disposal of the acid gas. The Board found that the evidence on this matter was clear and it therefore decided against reopening the hearing.

4. MINISTERIAL APPROVAL

In view of the subsequent material submitted to the Board by Imperial, the Board, in accordance with the provisions of section 38 of The Oil and Gas Conservation Act, forwarded the same to the Minister for his consideration, insofar as it affects matters of the environment.

The Minister of the Environment, having regard for Application No. 6823, the subsequent material submitted in connection therewith and for the intended disposition of the application by the Board, herein set out, has given his approval thereof, subject to the requirement that Imperial install a sulphur recovery plant with a minimum sulphur recovery efficiency to be specified by the Department of the Environment. In that regard the Minister's approval of the application will be incorporated in the Board's approval to be granted to Imperial, and the conditions imposed by the Minister, with respect to matters of the environment and sulphur recovery plant will be made conditions of the approval to be issued by the Board.

5. DECISION

The Board grants the application to increase the maximum hydrogen sulphide inlet rate to 110 MCFD and the maximum sulphur dioxide emission rate to 1.32 long tons per day subject the conditions that:

1. The requirements of the Minister of the Environment with respect to the installation at a sulphur recovery plant be met.

2. The tail gas from the sulphur recovery plant be incinerated and the exhaust gases vented through an incinerator stack.

3. Imperial's air quality monitoring requirements be increased to 12 exposure cylinder stations and one continuous monitor to be operated for six months during at least two separate periods of each year.

4. The sour D-2 A and D-3 B solution gas be conserved by compression to the amine treating plant.

5. Imperial direct all relief valves on separators, treaters and other pressure vessels containing oil within the plant to an open tank or tanks in accordance with section 8.031 of the Oil and Gas Conservation Regulations.

6. Imperial undertake a plant emission study and report its findings to the Board by September 30, 1977.

7. Imperial undertake a further noise survey in the area under the direction of Board staff.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

20, 1977
gary, Alberta

IMPERIAL OIL LIMITED

REPORT ON ALTERNATIVE MEANS
OF
HANDLING ACID GAS PRODUCTION
FROM THE D-1 AND BASAL QUARTZ POOLS
GOLDEN SPIKE

1 APRIL 1976

SUMMARY

This report discusses alternative means of handling acid gas from D-1 and Hewitt Basal-Quartz production at Golden Spike. It is recommended that the acid gas be flared in a stack designed to provide an SO_2 ground level concentration of 0.2 ppm or less.

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PURPOSE

The purpose of this report is to outline the re-evaluation of the alternatives for disposing of sour components of the D-1 and Hewitt-Basal Quartz gas streams at Golden Spike.

SCOPE

The relative merits and drawbacks of six processing alternatives for treating these acid gases are discussed in this report, and the alternatives are rated according to economic viability.

The six alternatives studied are ranked below in order of their economic attractiveness.

1. Flare Stack

2. Claus Sulphur Plant

3. Stretford Plant

4. Incineration and Dilution

5. Sour Gas Pipeline

6. Acid Gas Injection

BACKGROUND

In May 1971, Approval 1531 authorized Imperial to operate the Golden Spike Sweetening Plant and to produce up to 4.0 MMCF/D of feed stock containing not more than 80 MSCF of H_2S. (Maximum flare of 3.0 L.T. sulphur/day)

In the same year, Imperial requested a revision to Approval 1531, reflecting the low quantity of acid gas being flared at that time. The resultant Approval 1531C authorized Imperial to produce up to 7 MMCF/D of feed stock containing not more than 2.8 MSCF/D of H_2S. Flaring of acid gas was permitted from the 65-foot stack (maximum of 0.105 L.T. sulphur/day).

In December 1972, Imperial requested a revision to Approval 1531C permitting production of up to 7.0 MMSCF/D of Basal Quartz gas from Hewitt-Chevron wells or up to 5.0 MMCF/D of D-1 gas and the remainder of the 7.0 MMSCF/D maximum feed stock to be Hewitt-Chevron make-up. Acid gas was to be flared from a 200-foot stack. (Maximum of 110 MSCF/D of H_2S or 4.14 L.T. sulphur.

A public hearing was called in March 1973 to review the application which was opposed by residents in the area. As a result of the hearing and additional informal discussions with DOE staff, Imperial was requested to consider alternate methods to that of flaring acid gas.

Unsettled business conditions including uncertainty in Federal corporate tax legislation and Provincial royalty changes delayed the completion of the study until this point in time.

DISCUSSION

Pertinent economic and technical data for six alternate means of disposing of acid gas are discussed below and on the following pages.

For the purpose of this study it was assumed that project construction would commence in mid-1977. Investments obtained from the appropriate vendors and U.S. operators of similar facilities were increased to represent mid-1977 investments, as shown in Table 1. The cost estimates shown in Table 1 are not based on detailed plant design but are of a comparable quality sufficient for the purpose of economic screening of the proposed alternatives.

The production forecasts used in the study are detailed in Table 2.

Simplified process flow diagrams are shown in Figures 1-3 for each processing alternative discussed.

In addition, the 100 ppm H_2S isopleth is drawn around the sour production facilities at Golden Spike in Figure 4. The topographic map in Figure 4 was updated from a 1975 aerial photograph to show the latest urban development in the area. Operation of the system will therefore conform to the Guidelines for Urban Development.

1. FLARE STACK

A stack height of approximately 200 feet is sufficient to meet the specified maximum theoretical SO_2 ground level concentration of 0.2 ppm.

Greater operational flexibility is obtained with a flare stack since efficiency remains unaffected by large changes in feed gas composition, quantity, and/or the rate at which acid gas is produced for disposal. In contrast, processes that treat acid gas by means of a chemical reaction obtain maximum efficiency at design compositions, and feed rates and usually do not operate effectively under feed gas conditions which differ substantially from the design parameters. This is a significant factor in the case at hand since a sharp production decline is predicted for the D-1 and Hewitt gas pools at Spike and this will result in an early and rapid reduction in volume of the acid gas stream. Within the first eight years of production, the turndown ratio will be 0.4, i.e. the acid gas feed stream rate will be only 40% of the initial design rate.

1. FLARE STACK Cont'd

A concern, voiced by area residents, was that they would have a large smokey stack illuminating the country side for miles. In fact, the flaring of H_2S produces a non-luminous almost invisible flame entirely smoke free. In addition, the flame could be entirely shielded from view by installation of a uniflow-type acid gas burner which is attached to the top of the stack. The burner is reputed to increase exit velocity, exit temperature and combustion efficiency. (Manufactured by Black, Sivalls & Bryson Ltd.)

In summary then, the flare stack is the most attractive alternative examined. It offers relatively unlimited operational flexibility and reliability, is the lowest cost alternative and can be designed to meet environmental guidelines.

2. CLAUS SULPHUR PLANT

Correspondence and conversations with operators of small sulphur plants have indicated that there are numerous operating problems associated with small plants having a high turndown ratio, low H_2S concentrations and appreciable amounts of hydrocarbons in the acid gas feed stream. All three areas of concern exist at Golden Spike where we anticipate that a turndown of 40% in acid gas feed rate will be experienced after 8 years, where the H_2S concentration reaches only a maximum of 44%, and the hydrocarbon content in the acid gas stream is 2-4%.

Technical reasons for these areas of concern are as follows:

A. Turndown Ratio

In a Claus process, heat is recovered from an exothermic chemical reaction and is used to provide reheat in the process, with excess steam production being exported outside the Claus plant. Heat exchangers and waste heat recovery equipment, designed for initial production rates, cannot be adjusted for a wide range of load changes.

In small Claus plants, at feed rates less than 50% of design, heat energy must be imported for the process. At Spike this would cause higher operating and capital costs than normally associated with Claus plants and an unreasonably short term use of the expensive waste heat capital equipment.

B. Low H_2S Concentration

The efficiency of a Claus process is directly proportional to the concentration of H_2S in the plant feed. H_2S concentrations of about 50% or greater are required to maintain flame stability in a straight-through Claus process where approximately 60% of the total sulphur recovery occurs in the reaction furnace. The remaining recovery takes place in a series of one or more converter catalyst beds.

A split-flow Claus process can be used to process acid gas streams with lower H_2S concentrations, however, there is no sulphur recovery in the reaction furnace. As a result, total sulphur recovery must be provided by the catalyst beds, requiring more of them, reducing catalyst life and obtaining lower sulphur recovery than the comparable straight-through process.

Consequently, a straight-through Claus process would be chosen for Golden Spike but significant operational difficulty would result from the poor quality acid gas. These problems evolve because of the low (44% H_2S) fuel value which causes flame instability and more rapid catalyst deterioration.

C. Hydrocarbon Contamination of the Feed Stream

Presently, a DGA process is used at Golden Spike to sweeten sour gas. Characteristically, DGA units absorb more hydrocarbons than other sweetening units. This results in relatively high hydrocarbon content in the acid gas stream that would feed Claus process.

Hydrocarbons in a Claus unit result in dirty, off specification, non-marketable sulphur and carbonaceous deposits on the catalyst beds. Removal of these deposits requires that normal operations be suspended while the catalyst beds receive a high temperature regeneration (burn off). While this operation is normal to all sulphur plants, it is hazardous, creates catalyst deterioration, and usually results in higher than normal emissions to the atmosphere. The situation at Golden Spike is expected to require a higher frequency of burn offs thereby contributing significantly to higher operating costs, atmospheric emission, operational risk and down time.

D. Operational History

Information was taken from four existing small Claus sulphur plant operations*, all designed for less than 6 L.T. of sulphur and two of which have low H_2S concentrations similar to those in Spike. All were straight-through Claus processes with two converters. The acid gas feed stock was obtained from an MEA sweetening process in two instances and from a refinery caustic solution stripper in the other two processes. All plants required in-line auxiliary burners for supplemental heat with one plant also making use of one hot gas bypass.

The small plants cited all have characteristically low sulphur recoveries, high operating costs and operational shortfalls. These characteristics come about in part as a result of low H_2S concentration in the acid gas feed stock. Combustion instability is a common ailment and critical conversion temperatures are often not met. This ultimately creates inefficiencies throughout the process leading to higher emissions and lowered sulphur recoveries.

Unstable operations have occurred in three of the plants, primarily as a result of reaction furnace burner flame instability. One plant experiences 2 - 3 flame failures per week. Typically, the minimum flame temperature required to support efficient combustion is around 1600°F. Acid gas feed with a low H_2S concentration (fuel value) creates low temperatures and low thermal conversion efficiency in the combustion chamber. These factors subsequently lead to lower conversion in the catalyst beds, poor sulphur recovery and increased emissions. Similarly, variations in the acid gas feed rate at low plant loads has also resulted in unstable operations and had contributed further to low sulphur recoveries, primarily due to an excess conversion of H_2S to SO_2. Two Japanese sulphur plants have sulphur recoveries as low as 40% and 63% due to the combination of these factors at loads lower than design.

Another characteristic of these low efficiency plants is short catalyst life due to sulphur condensation, sulfate formation and carbonaceous deposits being formed on the reactor beds. The latter problem is due entirely to the presence of hydrocarbons in the acid gas feed. One small sulphur plant in England has reported a catalyst life of less than one year, primarily due to the aforementioned flame instability. In general, shutdowns exceeding 1 - 3 hours duration in the small sulphur plants discussed require the catalyst beds to be burned off to remove condensed sulphur. This in turn results in further catalyst thermal degradation. In contrast larger sulphur plants may go for 1 - 5 days on a shutdown without having sulphur condensation problems. It should also be noted that as the frequency of catalyst bed burnoff increases, so does the risk of losing a

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*See Appendix 1

D. Operational History Cont'd

reactor due to a runaway or uncontrolled burn.

One operator had operating experience with excessive turndown. With loads at around 50% of design, the small sulphur plants surveyed found that steam production was impossible by waste heat recovery from the reaction furnace production. In general, it was found that actual steam production corresponds to approximately 50% of the theoretical amount at the design load, due to disproportionately high heat loss from the plant, and accordingly a separate steam supply is required for heating, especially at low loads, where temperature control of the process is difficult. Correspondingly the recovery efficiency was found to decrease (40% and 63% as mentioned previously).

The results of the survey strongly indicate that fuel gas will be required to process the low H_2S acid gas at Spike in order to maintain temperatures at various points in the plant, adding to the operational complexity and costs of the process.

One of the main concerns of the D.O.E. with flaring the acid gas was the high H_2S concentration in the flare stack, (290,000 ppm), and the high SO_2 concentration in the combustion products, (29,000 ppm), Mr. Yurko informally proposed new SO_2 targets of 1000 ppm, over a ½ hour period, not to exceed an instantaneous level of 2000 ppm. The anticipated SO_2 concentration in the incinerator stack of a 2-stage Claus plant are tabulated below.

Acid Gas Feed From	No Stages	Theoretical S. Recovery %	SO_2 ppm in stack
1. 4MM/D D-1 + 1 MM/D Hewitt	two	95.6	6,761
2. 1MM/D D-1	two	95.7	7,254
3. 1MM/D D-1	one	88.3	18,070

The data indicates that a Claus process would not be capable of achieving the proposed SO_2 concentration targets.

D. Operational History Cont'd

In summary, all small plant operators cited are handicapped by poor plant operating characteristics, poor sulphur recoveries and high unit costs disproportionate to the size of the facility. We conclude that similar experience would be encountered with a small plant at Spike by reason of the close similarity in feed stream compositions and feed rate variables.

3. STRETFORD PLANT

A Stretford unit at Spike could reduce the H_2S content of the acid gas down to approximately 100 ppm. However, a higher capital investment is required as compared to a Claus plant and again there are high operating costs due to high chemical consumption and the need for tight control of reaction chemistry.

Turndown is not a problem with the solution used which contains sodium vanadate. Although not toxic, sodium vanadate is a heavy metal salt which leaves the disposal of spent solution a problem.

In summary a Stretford plant, although a viable alternative, is less economic than a Claus plant due to a higher cost.

4. INCINERATION AND DILUTION

Considerable equipment and fuel is required for incineration and dilution of the acid gas stream as shown in Figure 3. This is reflected by higher investment and operating costs as compared to the previous alternatives.

A 300-foot stack would be required with an internal tip diameter of 3 feet. Certainly more costly and more objectionable than a 200-foot stack required for just flaring the acid gas as in alternative one.

A stack top temperature in excess of 300°F would be required to prevent the formation of corrosive sulphuric acid from the effluents. Thus, fuel gas is not only required for incineration, but for heating the diluent air as well. With the forecast rate of increase in fuel costs, operating costs would be expected to increase significantly, particularly in the latter years of the D-1 project.

4. INCINERATION AND DILUTION Cont'd

In addition, operating a 400 Hp air blower to dilute the SO_2 concentration to 2000 ppm will surely add to the noise problem in the area while the total amount of SO_2 released is unchanged.

This alternative is less economic than the previous three.

5. SOUR GAS PIPELINE

The closest sulphur plant available is at Bonnie Glen. A 25 mile sour gas pipeline in the vicinity of populated areas would be required to transfer D-1 production for processing. With present public and industry concern regarding sour pipelines in populated areas, this does not appear to be a viable alternative.

In addition, the economics are not attractive as this alternative would require one of the highest investment costs.

6. ACID GAS INJECTION

Disposal of the acid gas by injection to an underground formation was considered but rejected on relative safety grounds. Dehydrating and compressing the high H_2S content gas to the required 1800 psi for injection involves difficult engineering and safety considerations that we do not recommend when other alternatives are available.

CONCLUSIONS

1. The alternative methods of handling acid gas from D-1 production in order of economic attractiveness are: a) flare stack, b) Claus sulphur plant, c) Stretford plant, d) incineration and dilution.

2. Two alternatives, a sour gas pipeline and acid gas injection are not recommended due to the problems they would present regarding urban encroachment and higher safety risks relative to the preferred alternatives.

3. A Claus sulphur plant is not well suited for small scale operations. The economic appraisal of this alternative suffers in comparison not only because of the fixed operating costs noted in Table 1, but also from the delayed production resulting from the higher than normal off-stream time which is associated with small plants of this type.

4. All urban settlement to date is outside the 100 ppm isopleth associated with the operation of the proposed facilities. (Figure 4)

RECOMMENDATIONS

It is recommended that acid gas resulting from D-1 and Basal Quartz production at Golden Spike be flared in a stack designed to provide an SO_2 ground level concentration of 0.2 ppm or less.

APPENDIX 1

SMALL CLAUS SULPHUR PLANTS SURVEYED

PLANT	SIZE (Long Tons Sulphur/Day)	H_2S (Mole % in Acid Gas)
Phillips Petroleum Bacton Plant (England)	6	40-45
Asia Oil Company (Japan)	2.3	94.5
Mitsubishi Petrochemical Company (Japan)	0.26	33.0
Mitsubishi Petrochemcial Company (Japan)	1.85	85.6

TABLE 1

ALTERNATE	1977 CAPITAL COST ($M)	OPERATING COST ($M/YEAR)[1]	FUEL (MCF/D)[2]
1. FLARE STACK	50	-	45
2. CLAUS PLANT	500	100	50
3. STRETFORD PLANT	700	120	≈ 45
4. INCINERATION & DILUTION	700	15	120
5. SOUR PIPELINE	900	15	200

(1) All operating costs are incremental to the flare stack case and also exclude fuel consumption.

(2) Also includes fuel requirement for other associated equipment as dew point control facilities, compressors and dehydration facilities.

Fuel - includes that required for ancillary operation, compression, dehydration and hydrocarbon recovery.

TABLE 2

RAW GAS PRODUCTION FORECAST

	HEWITT-BASAL QUARTZ MMCF/D	D-1 MMCF/D
1977	2.5	3.8
1978	2.2	4.1
1979	1.6	4.7
1980	1.0	4.9
1981	0.8	4.0
1982	0.6	3.2
1983	0.4	2.6
1984	0.3	2.2
1985	0.2	1.9
1986	0.1	1.5
1987	0.1	1.2
1988		1.1
1989		0.9
1990		0.7
1991		0.6
1992		0.5
1993		0.4
1994		0.3
1995		0.2
1996		0.1

TABLE - 3

RAW/ACID GAS COMPOSITIONS

	D-1		HEWITT	
	RAW	ACID GAS	RAW	ACID GAS
C_1	.8093		.8329	
C_2	.0722		.0754	
C_3	.0292		.0284	
iC_4	.0044		.0034	
nC_4	.0085		.0075	
iC_5	.0022		.0020	
nC_5	.0021		.0024	
C_6+	.0029		.0020	
N_2	.0239		.0213	
H_2S	.0206	.4337	.0005	.0231
CO_2	.0247	.5201	.0241	.9269
H_2O	-	.0462	-	.0500
A.G. MCF/D PER MMCF/D RAW		47.5		26.0
A.G. Btu/SCF		27.3		14.7
FUEL REQ'D to FLARE A.G.(MCF/D)		0		7.0

FIGURE 1

STRAIGHT-THROUGH CLAUS PLANT SCHEMATIC

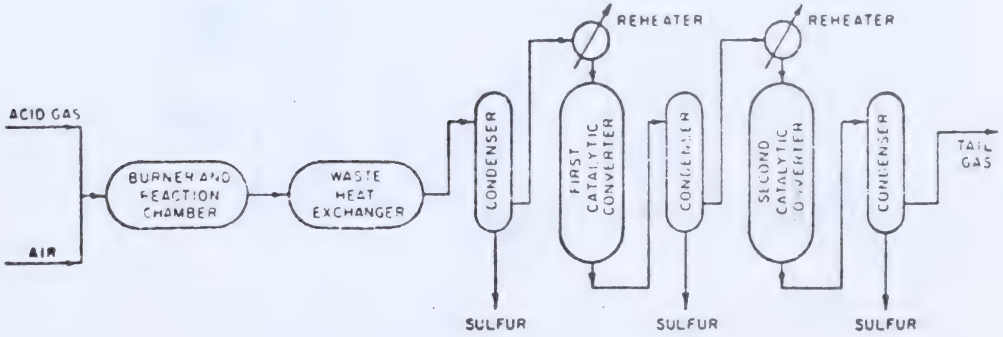
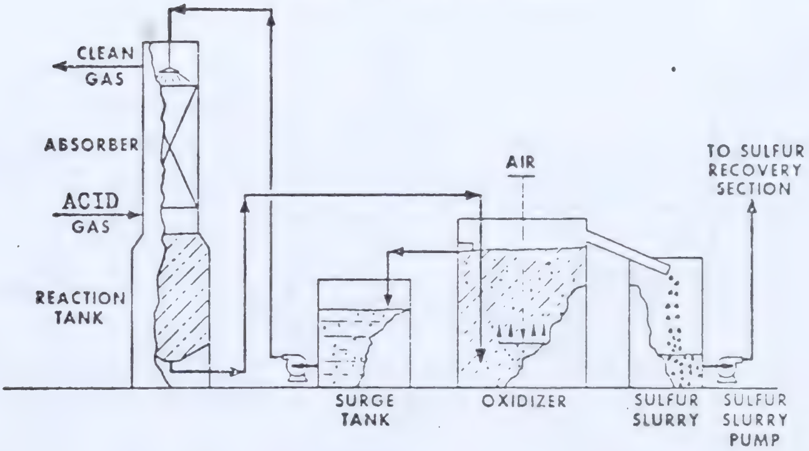


FIGURE 2

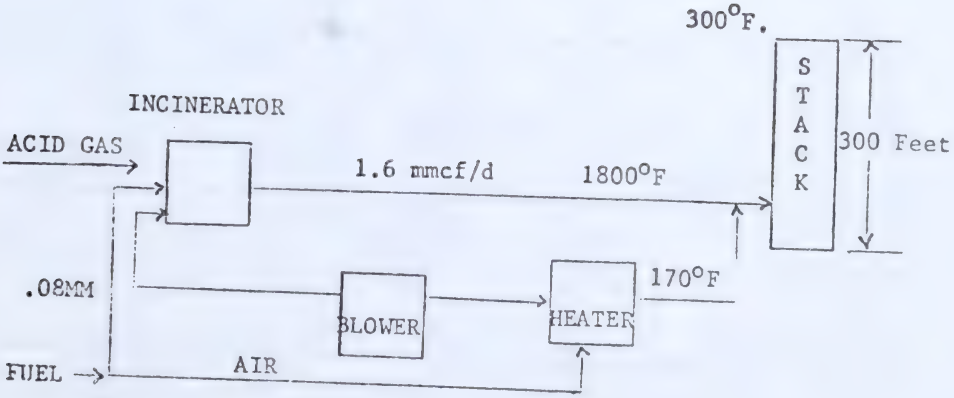
THE STRETFORD PROCESS

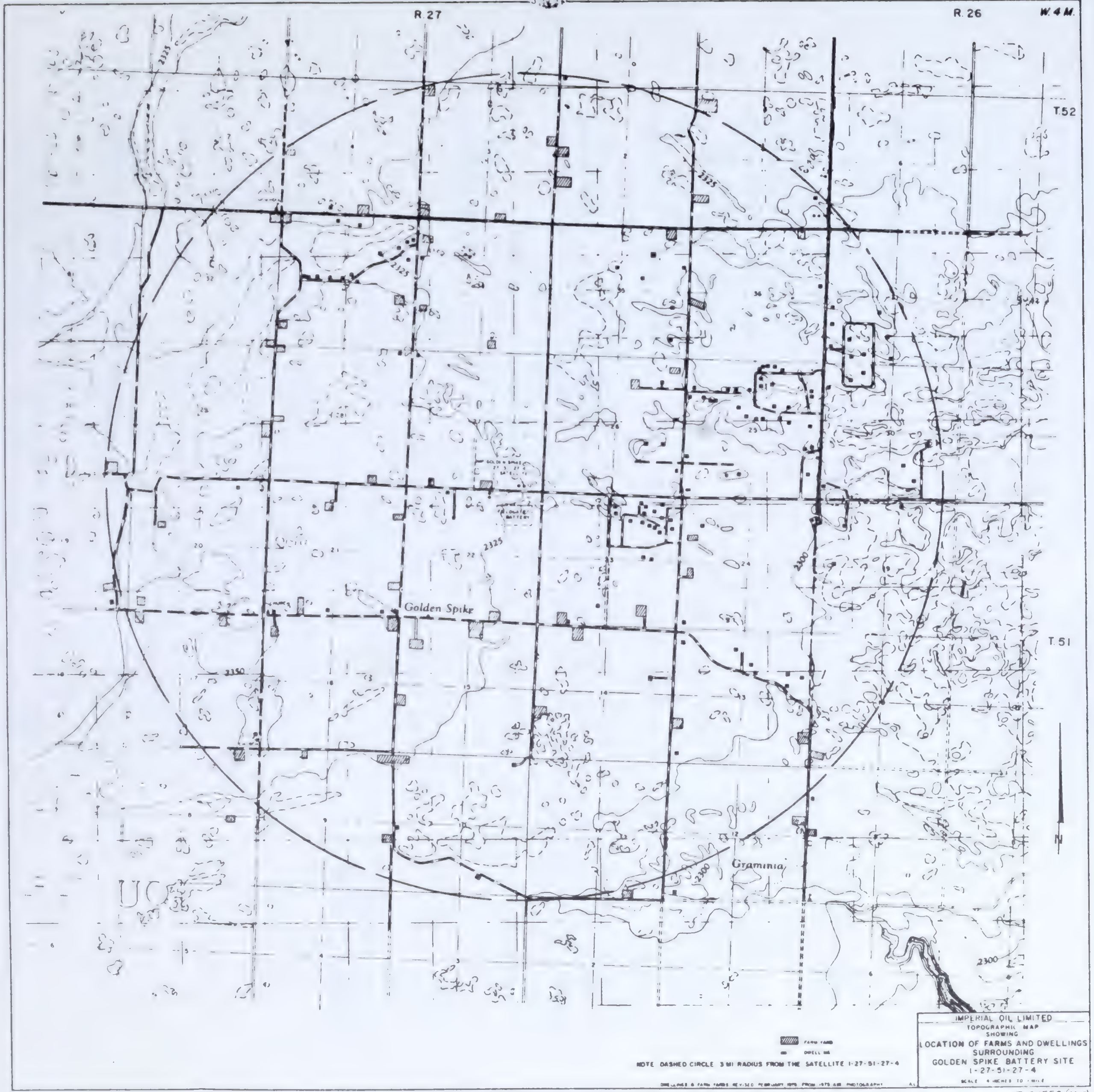


J. F. PRITCHARD & COMPANY

FIGURE 3

INCINERATION AND DILUTION





NOTE DASHED CIRCLE 3 MI RADIUS FROM THE SATELLITE 1-27-51-27-4

DWELLINGS & FARM YARDS REVISED FEBRUARY 1979 FROM 1973 AIR PHOTOGRAPHY

IMPERIAL OIL LIMITED
TOPOGRAPHIC MAP
SHOWING
LOCATION OF FARMS AND DWELLINGS
SURROUNDING
GOLDEN SPIKE BATTERY SITE
1-27-51-27-4
SCALE 4 INCHES TO 1 MILE

FIG 01

F10:558 (K 6)

ENERGY RESOURCES CONSERVATION BOARD

Decision 73 - 15
Application No. 6622

Application for Exemption From the Sulphur Recovery Guidelines Wimborne Gas Plant

THE APPLICATION AND HEARING

Application No. 6622 was submitted by Mobil Oil Canada, Ltd. for exemption from the sulphur recovery guidelines as outlined in the Board's Informational Letter No. IL 71-29 for the Wimborne Gas Plant. The Wimborne Gas Plant presently has an approved maximum sulphur inlet rate of 358 long tons per day and a required sulphur recovery efficiency of 93 per cent. The guidelines require a 94 to 96 per cent sulphur recovery efficiency by January 1, 1975 for plants processing favourable quality acid gas and from 100 to 400 long tons of sulphur per day.

The application was heard at the offices of the Energy Resources Conservation Board, Calgary on December 18, 1972 by examiners G. J. DeSorcy, P. Eng., and P. D. Larbalestier, P. Eng.

There were no interventions respecting the application.

APPEARANCES

The following appeared at the hearing:

	Represented By	Abbreviation Used in Report
Mobil Oil Canada, Ltd.	D. W. MacFarlane M. Basaraba, P. Eng. A. Koroluk, P. Eng. G. C. Derbowka, P. Eng.	Mobil
Board Staff	R. B. Dunbar, P. Eng. T. W. Nazarko, E.I.T.	

SUBMISSION OF THE APPLICANT

Mobil submitted that the present sulphur recovery efficiency of 95.2 per cent at the Wimborne Plant is within the range of 94 to 96 per cent set out in the guidelines and thus in its opinion the plant is currently meeting the guideline requirements. Mobil stated that the only reason it was applying for exemption from the guidelines was because a Board staff interpolation of the guidelines indicated that a sulphur recovery of 96 per cent was necessary to satisfy the guidelines.

Mobil interpolated the required sulphur recovery efficiency for the Wimborne Plant as 95.72 per cent taking into account the favourable acid gas quality and the maximum inlet capacity. Rounding this figure to the nearest one-half per cent would result in a required sulphur recovery efficiency of 95.5 per cent. Mobil pointed out that an increase in recovery from 95.2 to 95.5 per cent would reduce the sulphur emission to the atmosphere by only 0.5 long tons per day. Mobil stated that further interpolation within the favourable acid gas quality range (from 65 to 100 per cent H2S) for the Wimborne acid gas H2S content of 84 per cent, would result in a sulphur recovery efficiency of 95.09 per cent. Mobil also stated that although the maximum plant throughput is 358 long tons per day of sulphur, the average throughput is only 240 long tons per day. Interpolation of the guidelines using the average throughput would result in a sulphur recovery requirement of 94.93 per cent.

Mobil stated that the profitability of the sulphur plant at current and projected sales volumes is negative. It stated that any further investment in the sulphur plant to increase its sulphur recovery efficiency would be an added economic burden. It stated that it is presently operating the plant at the maximum recovery efficiency with the present facilities. Mobil also commented that minor modifications such as more frequent catalyst changes, better control facilities or a new sulphur coalescer would not increase sulphur recovery to 95.5 per cent. Taking into account the need for plant flexibility, Mobil stated that a 95 per cent sulphur recovery efficiency was the maximum practical recovery attainable by the existing facilities and that major modifications would be required to increase the recovery beyond this level.

Mobil presented a year by year cash flow analysis of the present sulphur plant operation that indicated a net revenue loss of $2.7 million through 1986. Mobil stated that in order to achieve a 96 per cent sulphur recovery efficiency it would have to add a third Claus stage at an estimated cost of $750,000. The addition of a third Claus stage would increase the net revenue loss through 1986 to $3.5 million. Mobil pointed out that the cash flow analysis was only to 1986 because the field deliverability in that year would necessitate plant modifications in order to continue production.

Mobil's economic analysis included operating costs for the sulphur plant allocated on the basis that sulphur is a coproduct of the processing operation. This method, as presented by Mobil, distributes operating and maintenance costs of all plant and field facilities on the basis of the volume handled by the various segments of the total Wimborne operation. This approach results in the charging of some 14.8 per cent of the Wimborne field unit operating costs and some 16.6 per cent of the gas and liquid processing costs to the produced sulphur.

For its economic analysis, Mobil estimated that the Wimborne Gas Plant sulphur sales volume and sulphur price would remain constant at 35 per cent of production and $6 per long ton respectively through 1986. It stated that it could not foresee improvement in the sulphur marketing situation with enough certainty to justify an increase in the sulphur sales volume or price forecast. Mobil stated that it does not plan to install melting or flaking facilities at the plant as there will be no sales from the sulphur stockpile.

Mobil stated that the Provincial ambient air quality standards for ground level concentrations of sulphur dioxide have been met except for a few isolated cases during plant upsets and equipment failures. It monitors ambient air quality in the Wimborne area for 2 months per year and conducted an infrared survey in 1971. It found no indication of apparent environmental damage due to SO2 emissions. In reply to questions respecting complaints, Mobil stated that it received 8 enquiries related to the plant and field operations in the last 18 months. It stated that most complaints were related to field operations but the exact cause of all complaints could not be determined.

FINDINGS OF THE EXAMINERS

The examiners find that:

1. Having regard for the capacity of the Wimborne Gas Plant and the quality of the feed gas going to the sulphur plant, the minimum sulphur recovery according to the guidelines should be 95.5 per cent. The examiners do not believe that an interpolation of the required sulphur recovery efficiency should be made within an acid gas quality range nor that the interpolation should reflect the average sulphur inlet rate. Accordingly, the examiners have based their interpolation of the guidelines on the maximum plant capacity and a favourable feed gas.

2. The present sulphur recovery at the Wimborne Gas Plant, some 95.2 per cent, is probably the maximum operating efficiency for the existing facilities. The likelihood is that a third Claus converter would be required to achieve a 95.5 per cent recovery.

3. The reduction in the emission of sulphur to the atmosphere for an increase in recovery efficiency from 95.0 to 95.5 per cent is relatively small, amounting to some 1.8 long tons per day at the maximum throughput rate or some 1.2 long tons per day at the average throughput rate experienced over the past year.

4. The co-product approach used by Mobil in allocating operating costs is not appropriate in assessing applications for exemption from the guidelines. The examiners believe that only the operating costs directly related to the sulphur plant operation should be used in such an assessment.

5. The necessary capital investment for a third stage as estimated by Mobil at $750,000 appears to be high. The examiners base this conclusion on a review of data collected by the Board on the addition of a third stage to plants of comparable size which would suggest the required investment at Wimborne to be in the order of $350,000. However, having regard for Mobil's estimate and due to the uncertainty in the inflationary rate for such facilities through 1975 the examiners have used in their analysis an investment in 1975 of $500,000.

6. The addition of a third Claus stage to the sulphur plant would not result in overall negative economics for the sulphur plant operation. The examiners economic analysis indicates a rate of return of 14 per cent on the overall sulphur plant operations from 1975 to 1986. The assumptions used in the analysis of the sulphur plant economics are consistent with those used by the Board in recent assessments of applications for exemption from the sulphur recovery guidelines and are summarized below:

(a) The required capital cost for a third Claus stage in 1975 was taken to be $500,000. A carry forward of $430,000 was added to this investment to provide for any unpaid balance as of January 1, 1975 on the existing sulphur facilities. The estimated unpaid balance was calculated by comparing the historical yearly sulphur revenue to the sum of the annual operating costs and a 10 per cent per year straight line depreciation on the original sulphur plant investment. The historical revenue was calculated by applying the Provincial average sulphur sales volume and sulphur price to the Wimborne sulphur production. Any operating costs or depreciation not covered by revenue was then considered as a carry forward.

(b) The operating cost of the sulphur plant was estimated as 8 per cent of the total capital investment in 1965 and thereafter was escalated at 3 per cent per year through 1986. An additional operating cost amounting to 8 per cent of the investment for a third stage was added in 1975.

(c) The sulphur production forecast submitted in the application was combined with the Board's estimate of the Provincial average sulphur sales and sulphur prices given below. No sales from stockpile were considered.

Year	Per Cent of Production Sold	Netback to Plant $/LT
1975	50	7.50
1976	50	9.00
1977	50	10.00
1978	52	11.00
1979	54	12.00
1980	56	12.00
1981	58	12.00
1982	60	12.00
1983	60	12.00
1984	60	12.00
1985	60	12.00
1986	60	12.00

7. On the basis of available monitoring and exposure cylinder results, the evidence respecting complaints put forward by Mobil at the hearing, and the few pollution complaints filed with the Board and the Department of the Environment, the Wimborne Gas Plant does not appear to present a serious pollution problem at this time. The fact that there were no interventions submitted to the hearing supports this conclusion.

RECOMMENDATION

The Board has indicated that its major consideration in establishing a sulphur recovery requirement level will be the overall economics of the sulphur plant operation since it expects all environmental requirements to be satisfied regardless of the sulphur recovery efficiency. Reference is made to the recent Petrogas Crossfield decision (Decision No. 73-2) wherein the Board stated that the sulphur recovery level required should be as high as practical having regard for both economics and sulphur recovery technology. The economic analysis using the procedures set out by the Board in Decision No. 73-2 indicates that the addition of a third Claus stage to the existing facilities at the Wimborne plant would not result in an overall uneconomic sulphur operation. Accordingly, exemption from the sulphur recovery guidelines for the Wimborne Gas Plant is not warranted on the basis of the Board's stated economic test.

The examiners recognize that Mobil is presently operating the sulphur plant well within the sulphur recovery range set out in the guidelines (94.0 to 96.0 per cent) and further, that an increase in sulphur recovery from 95.0 to 95.5 per cent would likely reduce total emissions to the atmosphere through 1986 by only some 5,000 long tons. Also, the examiners have determined that the incremental cost per long ton of sulphur that would be recovered in going from the existing recovery level to that prescribed by the guidelines is much higher than at other sulphur plants presently under consideration by the Board for exemption from the guidelines. This is due partly to the size of the recovery increment but also to the fact that the Wimborne Gas Plant will apparently be operating at an average throughput which is approximately 65 per cent of the maximum sulphur inlet capacity. The examiners also note that there does not appear to be a particular pollution problem related to the plant at this time.

As stated previously, an increase in the sulphur recovery for the subject plant from 95.0 to 95.5 per cent would reduce sulphur emissions under maximum throughput conditions by 1.8 long tons per day (from 17.9 to 16.1 long tons per day). Bearing in mind the special circumstances set out in the preceding paragraph, the examiners are of the view that the sulphur recovery level for the Wimborne plant need not be increased beyond 95.0 per cent provided that the maximum sulphur emission rate does not exceed that which would result if the guidelines were adhered to. The examiners therefore recommend that the minimum quarterly sulphur recovery at the Wimborne Gas Plant be increased from 93.0 to 95.0 per cent to be effective January 1, 1975, and that the maximum sulphur emission rate be set at a value consistent with a 95.5 per cent recovery and the maximum sulphur inlet capacity set out in Approval No. 1464.

VIEWS OF THE BOARD

The Board agrees with the recommendations of the Examiners.

DECISION

The Board has adopted the recommendations of the examiners respecting sulphur recovery efficiency and overall conditions of the environment.

Amendment of Approval No. 1464 is being issued concurrently with this decision.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig, P. Eng.
Vice-Chairman

Dated at Calgary, Alberta
August 23, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-16
Application No. 6783

EXEMPTION FROM SULPHUR RECOVERY GUIDELINES WINDFALL SULPHUR RECOVERY PLANT

1. THE APPLICATION AND HEARING

Texas Gulf Inc. applied under The Oil and Gas Conservation Act for exemption from the sulphur recovery efficiency guidelines set out in Board Informational Letter No. 71-29, for the Windfall Gas Processing Plant, located in the South half of Section 17, Township 60, Range 15, West of the 5th Meridian.

The application was heard on April 13, 1973, by the Energy Resources Conservation Board with G. W. Govier, P. Eng., V. Millard and D. R. Craig, P. Eng., sitting.

2. APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Texas Gulf, Inc.	E. W. Plum, P. Eng. F. J. Ronicker, P. Eng. B. Draper A. Oley T. G. White A. Neidermeyer, P. Eng. (of Amoco Canada Petroleum Company Ltd.)	Texas Gulf
Department of the Environment	R. Beaty	Department
Board Staff	R. B. Dunbar, P. Eng. L. E. Frederick, E.I.T.	

There were no interventions respecting the application.

3. BACKGROUND

Amoco Canada Petroleum Company Ltd., Hudson's Bay Oil and Gas Company Ltd., and Petrofina Canada Ltd., being the producers of natural gas in the Windfall, Pine Creek, and Pine Northwest Fields, transmit the sour raw gas from the subject fields for processing at the Windfall Gas Processing Plant. The

Windfall Plant is comprised of a gas plant which processes the sour raw gas for the recovery of sweet residue gas and liquid hydrocarbon products, and a sulphur plant which processes the acid gas from the gas plant for the recovery of sulphur. For purposes of clarity, the Board shall herein refer to the raw gas processing facility as the gas plant, the acid gas processing facility as the sulphur plant and the combined processing facility as the Windfall Gas Processing Complex or plant complex.

The Windfall Gas Processing Complex is operated by Amoco Canada Limited on behalf of itself, Hudson's Bay Oil and Gas Company Limited, (hereinafter called "Hudson's Bay"), Petrofina Canada Ltd. (hereinafter called "Petrofina"), and Texas Gulf Inc. Amoco, Hudson's Bay, and Petrofina jointly own the gas plant and Texas Gulf wholly owns the sulphur plant. The operation of the combined facility is regulated by Approval No. 1553, which was issued on July 15, 1971 to consolidate the previously separate gas plant and sulphur plant approvals.

Texas Gulf purchased the sulphur plant section of the Windfall Gas Processing Complex from Amoco, Hudson's Bay and Petrofina (hereinafter called "West Whitecourt Owners") in 1962. A contract entered into at that time obligated the West Whitecourt Owners to deliver the acid gas to the sulphur plant and Texas Gulf to purchase the acid gas at a purchase price based on the f.o.b. sales price of sulphur. A provision of the contract requires the West Whitecourt Owners to supply, free of charge, to Texas Gulf, all of the utilities required to operate the sulphur plant and to extend the utility service to any future sulphur plant expansion.

The Windfall Gas Processing Complex is currently permitted to process a maximum equivalent sulphur inlet volume of 2020 long tons per day and is required to recover, as elemental sulphur, a minimum of 94 per cent of the sulphur contained in the gas delivered to the plant complex and 95 per cent of the sulphur contained in the acid gas delivered to the sulphur plant.

Informational Letter No. IL 71-29 specifies that a plant operating at a maximum sulphur inlet rate of between 1000 and 4000 long tons per day and processing favourable quality acid gas shall recover 98 to 99 per cent of the sulphur contained in the gas delivered to the plant after December 31, 1974. By approximate interpolation based on the maximum inlet capacity of 2020 long tons per day the Board interprets the minimum sulphur recovery guidelines to require a sulphur recovery of 98.5 per cent for the sulphur plant.

In its application, Texas Gulf Inc. requested that the Windfall Sulphur Plant be exempted from the requirements set forth in Informational Letter No. IL 71-29 and that the Board continue to administer the sulphur recovery levels currently specified in Approval No. 1553.

A matter associated with the sulphur recovery to be required of the sulphur plant is the Board's evaluation of the adequacy of the incinerator stack. Calculations, using the Pasquill equation, indicate that a sulphur dioxide concentration of 0.68 parts per million could occur on hills approximately 1.7 miles south of the plant complex when the sulphur plant is operating at the maximum permitted emission parameters set out in Approval No. 1553. In November of 1971, the Board informed Amoco, the operator of the Windfall Gas Processing Complex, of the stack deficiency and requested that Amoco submit a written report to the Board outlining its assessment of the situation and its plan to rectify it. Amoco's initial action was to intensify the monitoring program in the vicinity of the plant complex to establish measured sulphur dioxide ground level concentrations in the suspect areas. Having regard for Amoco's action and the results of the monitoring program, the Board decided that the problem of the stack deficiency could be resolved at the time of an application respecting the minimum sulphur recovery efficiency guidelines.

4. DEFINITION OF ISSUES

The Board considers the following to be the issues involved in considering the application for exemption from the sulphur recovery efficiency guidelines and the related matters:

(a) consideration of the ownership situation

(b) economic impact of enforcing the sulphur recovery guidelines

(c) adequacy of the existing incinerator stack

(d) other environmental considerations.

5. CONSIDERATION OF THE OWNERSHIP SITUATION

5.1 Views of Texas Gulf

Texas Gulf stated that the Board should have regard for the unique ownership situation of the Windfall Gas Processing Complex in considering the application for exemption from the sulphur recovery guidelines. Texas Gulf testified that its sole interest in the plant complex was limited to the ownership of the sulphur plant and its only source of revenue was that realized from the sale of sulphur.

Texas Gulf further proposed that the Board should consider the acid gas purchase cost as an additional operating cost over and above that normally used by the Board in its economic evaluations. The applicant submitted that the acid gas purchase cost, which was a consequence of a contract executed in 1962 between itself and the West Whitecourt Owners represented a major portion of the gross operating cost of the sulphur plant. It was the view of Texas Gulf that the acid gas purchase cost was a justifiable operating expense since the acid gas purchase contract was entered into before the guidelines were introduced and as such did not represent a deliberate attempt to create a contractual advantage.

5.2 Views of the Board

The Board does not agree with Texas Gulf that the special ownership situation and the contractual arrangements for the purchase of the acid gas should influence significantly the Board's appraisal of the application. The Board believes that, where under its usual methods of evaluation enforcement of the guidelines is justified, the guidelines should not be departed from because of a peculiar contract position, even though the contract, as here, was entered into before the guidelines were introduced. Should the decision of the Board, following its usual method of evaluation, result in a disproportionate burden to Texas Gulf there are other remedies which may be applied. This is discussed further in Section 6.2.

6. ECONOMIC IMPACT OF ENFORCING THE SULPHUR RECOVERY GUIDELINES

6.1 Views of Texas Gulf

Texas Gulf stated that the sulphur plant should be exempted from the sulphur recovery guidelines on the basis of the absence of any adverse environmental effects from the sulphur plant operations and the poor economics that would result from the addition of a tail gas clean-up process.

The applicant submitted data to show that the sulphur plant has operated at a sulphur recovery efficiency in excess of the present requirement of 95 per cent of the sulphur supplied to it. The annual sulphur recovery efficiencies at the subject plant during 1970, 1971 and ten months of 1972 were 95.7 per cent, 96.1 per cent, and 96.1 per cent, respectively. Chromatographic analyses performed on the sulphur plant trains during the latter part of 1972 indicated that an average sulphur recovery of 96.3 per cent was being attained.

Texas Gulf stated that enforcement of the sulphur recovery guidelines would exert excessive strain on the economics of a sulphur operation which has no co-product source of revenue. The increased sulphur recovery and larger sulphur inventories associated with the installation of a tail gas unit would tend to further deteriorate an already marginal operation.

Texas Gulf submitted capital cost estimates at the hearing which indicated that the installation of an I.F.P. or Sulfreen tail gas unit to increase the sulphur recovery level of the sulphur plant to a design level of 98.5 per cent would require a total capital investment of between $5,300,000 and $6,200,000 and would increase total operating costs by $590,000 to $730,000 per year. Texas Gulf stated that its share of the capital investment would range from $3,900,000 to $4,700,000 and its portion of the operating costs would increase by $330,000 to $400,000 per year. The West Whitecourt Owners would assume the balance of the capital and operating costs through expanding the utilities service to the tail gas unit.

Texas Gulf further stated that it was of the belief that to achieve 98.5 per cent sulphur recovery on a consistent basis, the sulphur plant would have to be designed for a sulphur recovery of 99 per cent which would result in substantially higher investment and operating costs. Texas Gulf submitted that such a design would require a total capital investment of approximately $10,800,000 and total annual operating costs of $1,200,000. Texas Gulf stated that it would be responsible for $7,200,000 of the capital investment and $600,000 of the incremental operating costs while the West Whitecourt Owners would assume the balance of the costs.

Texas Gulf stated that the West Whitecourt Owners believe that they would be adequately sharing the cost of meeting the sulphur recovery guidelines by extending the utilities service to any necessary tail gas process and have refused to discuss any additional sharing of the cost of higher sulphur recovery.

Texas Gulf submitted cash flow analyses for several sulphur recovery levels covering the period 1972 to 1983 which did not include the capital investments or operating costs attributed to the West Whitecourt Owners. The economic analyses assumed sulphur prices of $6.75 per long ton f.o.b. plant in 1972, $6.30 per long ton in 1973 and $6.00 per long ton throughout the remainder of the life of the project to 1985. Sulphur sales were assumed to be 62 per cent of sulphur production in 1972, and were escalated at approximately 4 per cent per year until 1983 at which time sales would exceed production and sales from sulphur storage would commence. In 1986, the sulphur plant operation would be shut down, but sulphur sales from storage would continue until 1988, at which time the total sulphur inventory would have been sold. The applicant derived the acid gas purchase cost from the sulphur production forecast and the forecast selling price of sulphur in accordance with its contract with the West Whitecourt Owners. The acid gas purchase price was estimated to $2.75 per long ton of sulphur production in 1972, $2.30 per long ton in 1973, and $2.00 per long ton for each successive year.

Texas Gulf used the unit of production method which is based on depreciating capital investments according to the fraction of total reserves produced, to determine that $6,324,938 of past sulphur plant investment should be carried forward to January 1, 1972 as unrecovered investment. At present sulphur recovery levels, Texas Gulf's economic analysis indicated a before tax undiscounted cash profit at the end of 1988 of $9,999,499 and an after tax undiscounted cash profit of $4,402,160. The discounted rate of return for the after tax analysis was calculated to be approximately 4.5 per cent. Installation of the I.F.P. tail gas facilities to achieve a design recovery of 98.5 per cent would cost an additional $4,810,000 resulting in a before tax undiscounted cash loss in 1988 of $2,588,173. Increasing the design sulphur recovery to 99 per cent would cost an additional $7,206,000 resulting in a before tax undiscounted cash loss in 1988 of $3,618,001.

Texas Gulf emphasized that because the acid gas purchase cost is dependent on both sulphur price and total sulphur production, an increase in the sulphur selling price could worsen the total cash flow for the project depending on the yearly sulphur sales.

Texas Gulf asked that in the event that the Board denies the subject application for exemption from the sulphur recovery guidelines, then the Board should consider Texas Gulf's letter of April 13, 1973, submitted as exhibit seven, as an application for an extension of time to January 1, 1976 either to reapply for exemption from the guidelines or to apply for approval of proposed modifications to meet the guidelines.

6.2 Views of the Board

As stated in recent decision reports with respect to similar applications, it is the Board's view that notwithstanding the satisfactory operation of a plant with respect to environmental impact, the sulphur recovery level should be as high as practical having regard for both economics and sulphur recovery technology.

Using the method of analysis described in Decision 73-2, the Board has examined the economics of the sulphur plant with the addition of a tail gas clean-up facility to determine the discounted rate of return for operations after 1974. The Board calculated the undepreciated value of past sulphur plant investments at December 31 of 1974 to be $1,002,000 based on a ten per cent per year straight line depreciation subject to available cash flow. The Board estimated that a further investment of $4,500,000 would be required to increase the sulphur recovery level to 98.5 per cent. This is less than the applicant's figure of between $5,300,000 and $6,200,000; however, the applicant's estimates included a capital expenditure to purchase additional power generating equipment to operate the tail gas facility. The Board's economic evaluation includes tail gas plant power costs in the total operating cost assessment by assuming the power requirements are purchased from a utility. Accounting for both unrecovered past investment and the necessary new capital, a total equivalent investment of $5,502,000 was used in the economic analysis of the Board.

The Board also estimated the operating costs after installation of a tail gas plant and including all utilities to be $1,433,000 in 1975. The equivalent cost calculated by the Board from the applicant's data, is in the range of $1,230,000 to $1,310,000. The Board escalated the annual total operating costs at 3 per cent per year but made allowances for a decline in operating costs with declining production later in the life of the scheme. Texas Gulf's independent cash flow analysis showed an escalation of 3 per cent per year in operating costs, but did not reflect declining production prior to the complete shut down of the sulphur plant in 1986.

The Board based its analysis on its own forecast of sulphur sales and sulphur prices and used Texas Gulf's forecast of sulphur production related to the installation of an I.F.P. tail gas unit. The data used in the Board's economic evaluation is summarized on Table 1.

The Board notes that its estimate of percentage of sulphur sold is not as optimistic as that submitted by the applicant; but, the Board's sulphur price forecast is more optimistic. The Board believes that the use of its forecasts which are the sa as those utilized in Decision 73-7 continues its objective of treating all applications for exemption from the sulphur recovery guidelines on a consistent basis.

The Board's evaluation indicated a discounted rate of return before taxes of 24 per cent at an illustrative royalty rate of 25 per cent. The economics would become more favourable if the Board were to consider the incinerator stack cost saving made by meeting the Provincial Ambient Air Standards through increased sulphur recovery as opposed to the construction of a new 800-foot incinerator stack. The Board concludes that its economic analysis shows that the additional investment and expens in meeting the sulphur recovery guidelines is clearly justified and should be required.

The Board believes that Texas Gulf has had adequate notice of the Sulphur Recovery Guidelines, and does not see any grounds for granting Texas Gulf's application for an extension of time to January 1, 1976 to further study the measures to meet the sulphur recovery required by the guidelines.

With the Board's decision not to grant the application and to require a sulphur recovery of 98.5 per cent, and because of the special ownership and contractual situation, there will arise the question of how the cost of compliance with the Board's requirement will be met. The Board does not believe the arrangements between the West Whitecourt Owners and Texas Gulf contemplated the type of sulphur plant expansion here required. The continued operation of the sulphur plant at Windfall is important to the West Whitecourt Owners as well as to Texas Gulf. The Boar believes the West Whitecourt Owners and Texas Gulf should renegotiate their contracts to provide for a more appropriate allocatio of the additional costs and urges that this be done. The Board asks that the West Whitecourt Owners and Texas Gulf advise it by December 31, 1973 of the results of any such rengeotiation. Dependent upon the results, the Board would then consider

(a) separately requiring Amoco, Hudson's Bay and Petrofina to process the gas produced by them for the necessary further recovery of sulphur; such a requirement, in accordance with section 21 of The Oil and Gas Conservation Act, would override the terms and conditions of any conflicting contracts; or,

(b) directing Texas Gulf to process the gas for the necessary further recovery of sulphur and recommending to the Lieutenant Governor in Council that the Board be directed to prepare a scheme under section 131 of the Oil and Gas Conservation Act to compensate Texas Gulf for loss it may suffer from compliance with the direction; or,

(c) such other action as deemed appropriate.

7. ADEQUACY OF THE EXISTING INCINERATOR STACK

7.1 Views of Texas Gulf

Texas Gulf submitted evidence which indicate that the half-hour average tree top concentration of sulphur dioxide, calculated for the existing 400-foot stack and utilizing the maximum emission rates permitted by Approval No. 1553, can exceed the Provincial Standard of 0.2 parts per million under various atmospheric conditions. Texas Gulf stated that the calculated concentrations are much higher than would be encountered under present normal operating conditions and that air monitoring has not indicated the same high concentrations as calculated by the Pasquill method. Texas Gulf contended that the Pasquill method is, therefore, extremely conservative and the extent of the conditions at which the maximum sulphur dioxide levels occur is in reality quite limited.

Texas Gulf stated that calculations for the present 400-foot stack indicated that a sulphur recovery efficiency in the order of 99 per cent would have to be achieved to maintain the sulphur dioxide concentration below 0.2 parts per million, whereas the Board's sulphur recovery efficiency guidelines would require that the sulphur plant attain a sulphur recovery of 98.5 per cent.

Texas Gulf stated that, at the now approved sulphur dioxide emission rate of 210 long tons per day and a stack emission temperature of 1050 degrees Fahrenheit, an incinerator stack of 800 feet in height would be required to maintain the sulphur dioxide concentration below 0.2 parts per million under all atmospheric conditions. The applicant stated that it is not possible to attain an 800-foot incinerator stack by extending the existing 400-foot stack and that a new stack would have to be constructed to achieve the desired sulphur dioxide ground level concentration.

In reply to questions from the Department of the Environment, the applicant stated that the sulphur dioxide concentration of the stack gases was approximately 11,000 parts per million when the sulphur plant is operating at a 95 per cent sulphur recovery efficiency. The applicant indicated that the plant has operated at an average sulphur recovery efficiency of

96.3 per cent during 1972 and it anticipates it can maintain that recovery level in the future.

Texas Gulf concluded that no extensive damage has occur to the ecology of the area due to the sulphur plant operation and that modifications to or replacement of the existing stack is not required.

7.2 Concerns of the Department

The primary concern of the Department is the high calculated ground level concentration of sulphur dioxide resulting from the actual operating conditions at the sulphur plant. The Department is of the view that all plants should be designed to comply with the calculated standard of 0.20 parts per million of sulphur dioxide at ground level under all operating conditions.

7.3 Views of the Board

With the 98.5 per cent sulphur recovery to be required, the Board has determined that the calculated tree top concentratio of sulphur dioxide could be maintained below 0.2 parts per million with the present 400-foot incinerator stack and by maintaining a stack gas exit temperature of 1000 degrees Fahrenheit.

8. OTHER ENVIRONMENTAL CONSIDERATIONS

8.1 Views of Texas Gulf

Texas Gulf submitted sulphur dioxide monitoring results exposure cylinder readings, stack survey analyses, and the results of two infrared aerial surveys to indicate that the sulphur plant has not adversely affected the ecology of the area in the past ten years of operation.

The applicant maintained that high sulphur dioxide readings recorded prior to May of 1972 could be attributed to sour gas flaring at the plant complex and at two water injection wells operated by Petrofina. The practice has since been discontinued.

Texas Gulf stated that the results of two infrared aeri surveys conducted in 1971 and 1972 indicate that no permanent damage had occurred to the area as a result of the sulphur plant emissions. The survey indicated that some environmental stress ha occurred in the area of the plant, but Texas Gulf contended that t effects were transient and very minor. The applicant stated that, since there are other industrial operations in the area which are potential sources of sulphur pollutants, the environmental stress could not be attributed solely to the subject sulphur plant.

Texas Gulf stated that the residents of the area have never filed a complaint against the operation of the plant complex

8.2 Concerns of the Department

The Department is concerned that the environmental studies conducted in the region of the plant complex revealed that the vegetation in the area has experienced varying degrees of stress due to sulphur dioxide.

8.3 Views of the Board

The Board accepts the studies submitted by Texas Gulf regarding monitored air quality and vegetation and soil conditions in the vicinity of the plant complex as a satisfactory indication that to date, even moderate environmental damage due to the sulphur plant operation has not occurred. The Board appreciates the past efforts undertaken by the applicant to determine, and to remedy, the environmental problems in the area. The absence of any complaints from residents in the vicinity is of limited significance because the plant complex is located in a relatively sparsley populated region.

With the higher sulphur recovery, the Board is satisfied that no adverse environmental impact should result from the sulphur plant operation.

9. DECISION

The Board denies the application by Texas Gulf for exemption of the Windfall Sulphur Plant from the minimum sulphur recovery efficiency guidelines and requires that the sulphur plant meet a sulphur recovery requirement of 98.5 per cent after December 31, 1974. Amendment of Approval No. 1553 is being issued concurrently with this decision.

The Board dismisses the supplemental application of Texas Gulf dated April 13, 1973 for an extension of time either to reapply for exemption from the guidelines or to apply for approval of proposed modifications to meet the guidelines.

The Board expects that Texas Gulf will apply prior to September 30, 1973, unless a later date is stipulated by the Board, for approval of the proposed modifications necessary to meet the 98.5 per cent requirement.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

Dated At Calgary, Alberta
August 28, 1973

Table 1

Data Used for Board Evaluation of Windfall Sulphur Recovery Plant Economics

Year	Investment* $ x 10^3	Annual Operating Cost $ x 10^3	Annual Sulphur Production LT x 10^3	Percentage of Sulphur Sold	Plant Netback Sulphur Price $/LT
1975	4,500	1,433	589	50	9.00
1976		1,476	591	50	10.00
1977		1,520	580	50	11.00
1978		1,566	570	52	12.00
1979		1,613	559	54	12.00
1980		1,661	552	56	12.00
1981		1,711	543	58	12.00
1982		1,762	536	60	12.00
1983		1,813	599	60	12.00
1984		1,870	591	60	12.00
1985		1,601	381	60	12.00

* Does not include carry forward of undepreciated investment

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-17
Application No. 7020

TRANSMISSION LINE - IMPERIAL OIL ENTERPRISES LTD. REFINERY, EAST EDMONTON

INTRODUCTION

The subject application was made under sections 9 and 11 of The Hydro and Electric Energy Act by Calgary Power Ltd. for a permit to construct and a licence to operate two - 138 kV electric transmission lines from the applicant's East Edmonton Substation CP 38S to an oil refinery owned by Imperial Oil Enterprises Ltd. and for a 138/13.8 kV substation, to be located at the refinery.

THE BACKGROUND TO THE APPLICATION AND THE APPLICATION

The purpose of the proposed transmission lines, as outlined by the applicant, will be to provide two independent means of electric energy supply from the applicant's East Edmonton Substation CP 38S to the Imperial Oil Enterprises Ltd. refinery now under construction.

The proposed transmission lines would be located on two separate rights-of-way. The line, designated as CP 738L (South), would commence at the applicant's East Edmonton Substation CP 38S, located in the northeast corner of Section 31, Township 52, Range 23, West of the 4th Meridian and would proceed in a south-westerly direction on the south side of the Canadian Pacific Railway right-of-way to the south boundary of the northwest quarter of Section 31. The line would then continue west to a point in the approximate center of the south boundary of the northeast quarter of Section 36, Township 52, Range 24, West of the 4th Meridian and from there in a north and north-westerly direction, it would cross Highway 16A slightly west of the west boundary of LSD 1 and 8 of Section 1, Township 52, Range 24, West of the 5th Meridian and then finally easterly to Substation CP 95S located on the property of Imperial Oil Enterprises Ltd., in the LSD 8 of Section 1, Township 53, Range 24, West of the 4th Meridian, all of which is shown on Appendix 1.

The line designated as CP 737L (North) would also originate at the applicant's East Edmonton Substation CP 38S, but would proceed north across Highway 16A into LSD 1 of Section 6, Township 53, Range 23, West of the 4th Meridian and continue northeast into LSD 5 of Section 5, and then turn west along the north boundary of the southeast quarter of Section 6. The line would then continue north a short distance along the east boundary of the north west quarter of Section 6, then west through LSD 11 and 12 of Section 6 and LSD 9 and 10 of Section 1 Township 53, Range 24, West of the 4th Meridian From that point the line would continue south into LSD 7 and then east into Substation CP 95S in LSD 8, all of which is shown on Appendix 1.

The subject application was advertised for objections by a Notice issued on April 17, 1973. Upon publication an objection was received from the City of Edmonton, to the location of the proposed line CP 737L (North). No other objections were received in response to the Notice.

The Board upon consideration of the objection requested that the applicant submit further information or proposals regarding possible alternative routes for the proposed line CP 737L (North).

Officials of the applicant, the City of Edmonton, and Imperial Oil Enterprises Ltd. met to discuss possible alternative routes for the line subsequent to which the City of Edmonton offered to withdraw its objection, by letter dated July 3, 1973 if the applicant would agree to some certain conditions, including a revised route.

The applicant, by letter dated July 10, 1973, agreed to some of the conditions proposed but could not completely agree with the revised route submitted by the City of Edmonton, since the proposed revision of the line, related to its location on the property of Imperial Oil Enterprises Ltd. and their approval would also be required. The applicant also expressed doubts about the safety of the revised route with respect to the refinery.

The applicant, in a letter dated July 10, 1973, requested that, in order to meet the in-service date of October 1, 1973, for power to the new refinery, the Board issue a permit and licence to allow construction and operation of the line designated as CP 738L (South) and the new Substation CP 95S since there were no objections to this portion of the proposed facilities. The Board subsequently issued Permit and Licenc No. CP 73-27 and CP 73 28 on August 17, 1973, approving the construction and operation of the line designated as CP 738L (South) and Substation CP 95S.

Imperial Oil Enterprises Ltd., by letter dated July 12, 1973, expressed the view that the revision to the route of the line, proposed by the City of Edmonton, was unsuitable.

The Board staff, after a review of the submissions and associated material and a review of a field inspection by staff members on June 6 1973, recommended to the Board that sufficient information was available to reach a decision regarding the disposition of this application.

DEFINITION OF THE ISSUES

The Board is required under The Hydro and Electric Energy Act to secure the observance of safe and efficient practices and to ensure environmental conservation in the public interest in the transmission of electric energy.

The Board considers the principal issues to be whether the need for the subject transmission lines is in the public interest and whether the location of the proposed transmission line CP 737L (North) is satisfactory having regard for the residents in the area of the refinery, the City of Edmonton's objection and the needs of the applicant to serve the refinery in a safe and efficient manner.

VIEWS OF THE APPLICANT

The application outlined the need for an adequate supply of electric energy for the safe and efficient operation of the refinery and the applicant stated that this could best be achieved by two independent transmission lines to supply Substation CP 95S.

The applicant stated that the lines would have a negligible effect on the environment because of the already highly industrialized state of the area through which the lines would be routed.

The applicant agreed to accept some of the conditions requested by the City of Edmonton but could not agree with the revised route of the line proposed by the City where such revision might create problems regarding satisfactory operation and safety.

INTERVENTION BY THE CITY OF EDMONTON

The City of Edmonton did not object to line CP 738L (South) but did object to the route of line CP 737L (North) on the basis that:

(1) the proposed right-of-way would lead to further destruction and deterioration of the natural environment of the ravine situated on the Imperial Oil Enterprises Ltd. property, and

(2) would add another industrial element to the skyline when viewed from the residential area surrounding the refinery site.

The City of Edmonton recommended that in order to eliminate or at least minimize the visual and environmental impact, the routing of the north and west segments of the proposed transmission line CP 737L (North) be relocated toward the interior of the refinery site and that:

(1) the line not intrude into the ravine lands, and

(2) the line not be visible from the residential areas to the north and west of the Imperial Oil Enterprises Ltd. refinery.

The City of Edmonton submitted a proposed alternative route which is shown on Appendix I.

SUBMISSION BY IMPERIAL OIL ENTERPRISES LTD.

Imperial Oil Enterprises Ltd. submitted in support of the application that, since part of the line is to be located on Imperial Oil Enterprises Ltd. property and will serve only the Imperial Oil Enterprises Ltd. refinery, the routing of the line is a matter in which they must be involved, and that the application should be approved as originally proposed.

Imperial Oil Enterprises Ltd. further submitted that the rerouting of the line as proposed by the City of Edmonton would not be suitable for the following reasons:

(1) The Line would be located near several large storage tanks, in which light hydrocarbons will be stored and there would be some degree of hazard to the line, should a fire occur at the tanks or should the line itself cause ignition of vapours being released from the tanks under abnormal conditions;

(2) The line would be located near a water cooling tower, the vapours from which could cause icing of the line under unfavourable winter weather conditions;

(3) A guyed, double-pole structure would be required on the east side of the ravine and would have to be located on a limited space between the refinery road and the top of the ravine bank, restricting access and preventing the use of this area for other purposes, and the appearance of a structure such as this would be less desirable than that of the single pole that would be used on a straight run; and

(4) Routing the line back and forth across the ravine, as proposed by the City of Edmonton, would not improve the appearance of the line and the poles would be of at least the same height as for the applicant's proposed route.

VIEWS OF THE BOARD

The Board agrees that two transmission lines are required in order to provide an adequate and reliable supply of electric energy for the efficient operation of a refinery of the size proposed by Imperial Oil Enterprises Ltd.

The Board further notes that the lines are proposed in an area which is highly industrialized and agrees that the lines would therefore have a minimal effect on the environment in such an industrial setting.

The Board has considered and accepts the submission of Imperial Oil Enterprises Ltd. on the basis that where a section of the proposed line would be installed entirely on Imperial Oil Enterprises Ltd. property, the routing of the line is a matter in which Imperial Oil Enterprises Ltd. should be involved. The Board believes that in the placement of the line, safe and reliable operation must be prime considerations in addition to impact on the industrial environment.

The Board agrees with the City of Edmonton that, in principle, the line will add some visual clutter to the industrial skyline, but believes that the current expansion of the refinery will dominate the view and form a background against which the line will form only a small part of the whole industrial panorama. The proposed construction should be such as to reduce any visual impact as much as possible and to minimize damage to natural vegetation and ravines; and therefore the Board believes that the modifications proposed in the applicant's letter of July 10, 1973 should be implemented.

DECISION

The Board, having considered the application and submissions thereto, and having previously issued Permit and Licence No. CP 73-27 for transmission line CP 738L (South) and Permit and Licence No. CP 73-28 for Substation CP 95S approves the construction and operation of transmission line CP 737L (North) as proposed in the application and as modified by the proposals contained in the applicant's letter, dated July 10, 1973.

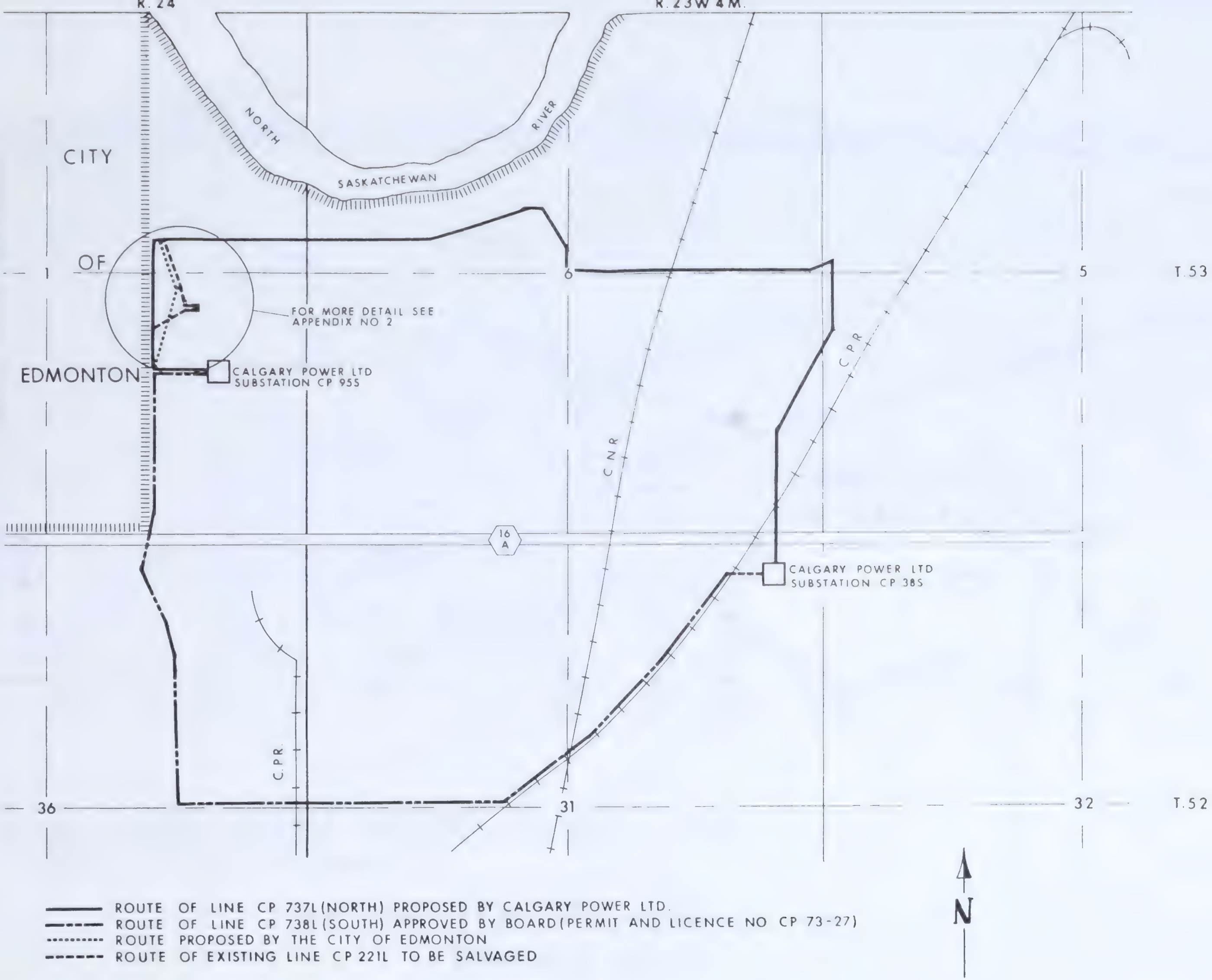
The route of CP 737L (North) shall be as shown on Appendix 1.

ENERGY RESOURCES CONSERVATION BOARD

J.I. Strong

J. I. Strong
Board Member

DATED at Calgary, Alberta
September 10, 1973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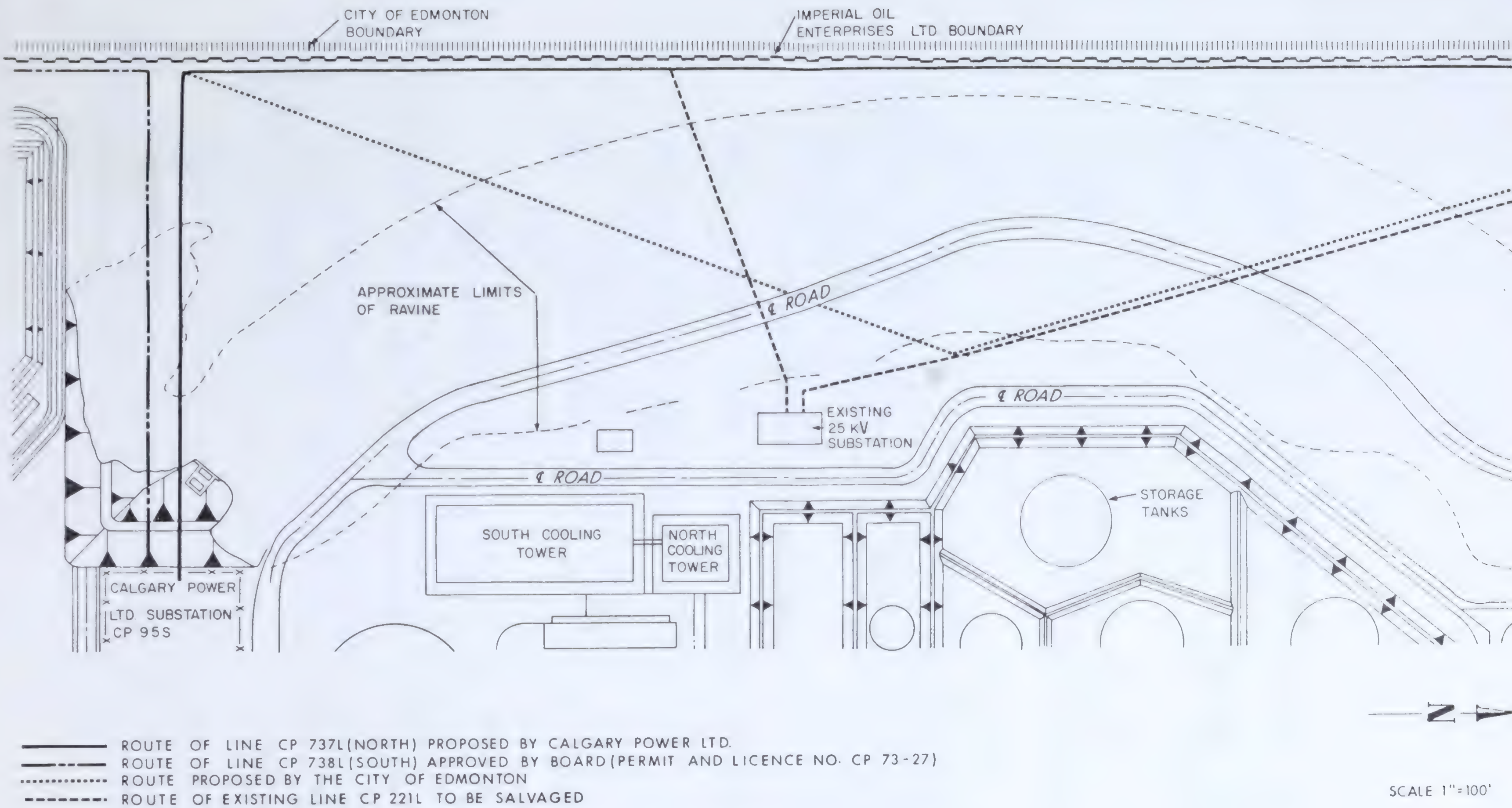
ROUTE OF LINE CP 737L (NORTH) PROPOSED BY CALGARY POWER LTD.
ROUTE OF LINE CP 738L (SOUTH) APPROVED BY BOARD (PERMIT AND LICENCE NO CP 73-27)
ROUTE PROPOSED BY THE CITY OF EDMONTON
ROUTE OF EXISTING LINE CP 221L TO BE SALVAGED

DECISION 73 - 17 APPLICATION NO. 7020

APPENDIX NO. 1


CITY OF EDMONTON BOUNDARY
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CALGARY POWER LTD. SUBSTATION CP 95S
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SCALE 1"=100'
ROUTE OF LINE CP 737L (NORTH) PROPOSED BY CALGARY POWER LTD.
ROUTE OF LINE CP 738L (SOUTH) APPROVED BY BOARD (PERMIT AND LICENCE NO. CP 73-27)
ROUTE PROPOSED BY THE CITY OF EDMONTON
ROUTE OF EXISTING LINE CP 221L TO BE SALVAGED

DECISION 73-17 APPLICATION NO. 7020

APPENDIX NO. 2

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-18
Proceeding No. 7203

DELAY IN INITIATION OF PRESSURE MAINTENANCE SCHEME MEEKWAP D-2 A POOL

1.0 THE SUBMISSIONS AND HEARING

The Board, by notice issued July 11, 1973, called a hearing to hear representations from operators and interested persons to show cause why the Board should not shut in or significantly restrict the production from the Meekwap D-2 A Pool until such time as a scheme to maintain the pressure in all parts of the pool has commenced.

Submissions respecting the hearing were filed as follows:

(a) the staff of the Energy Resources Conservation Board,

(b) Gulf Oil Canada Limited,

(c) Samedan Oil of Canada, Inc.,

(d) PanCanadian Petroleum Limited as an interested party, and

(e) Canadian Superior Oil Ltd. for the purpose of cross-examination.

Interventions were filed by Gulf Oil Canada Limited and Samedan Oil of Canada, Inc. to the Board staff submission.

The submissions and interventions were heard on August 8, 1973, by the Energy Resources Conservation Board with D. R. Craig, P. Eng., J. I. Strong, P. Eng and G. J. DeSorcy, P. Eng., sitting.

1.0 APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Gulf Oil Canada Limited	T. F. Randall, P.Eng. R. V. Lang, P.Eng.	Gulf
Samedan Oil of Canada, Inc.	F. W. Kelly	Samedan
PanCanadian Petroleum Limited	S. J. Springer, P.Eng.	PanCanadian
Canadian Superior Oil Ltd.	J. Peake, P.Eng. R. W. Stanich, P.Eng.	Canadian Superior
Energy Resources Conservation Board	N. G. Berndtsson, P.Eng. N. I. Dell, P.Eng. P. M. Stanton, P.Eng.	Board Staff

2.0 THE BACKGROUND

The need for pressure maintenance in the Meekwap D-2 A Pool was initially considered at a meeting of the Board staff and the Operators of the Meekwap D-2 A Pool early in 1972. The Operators agreed to make early application for approval of a water flood scheme in order to commence water injection as soon as possible. Gulf made such an application, on behalf of the Working Interest Owners, in July 1972. Model studies and recovery calculations were to be submitted at a later date, at which time the Board would determine recovery factors. The application was granted and Approval No. 1806 was issued to Gulf in September 1972, and provided therein that water injection was to commence on or about January 1, 1973.

In January 1973 Gulf requested an extension of the date for commencement of injection to the fall of 1973. At a meeting on February 22, 1973, called by the Board staff to discuss the lack of progress, it was agreed by the Board staff, Gulf and Samedan that Gulf would submit to the Board on or about April 1, 1973, an application for amendment of the water flood approval requesting a water injection well change and a commencement date change. No application was received by the Board in April 1973, but in June 1973, at the request of the Board, Samedan (to whom the role of principal pool operator had devolved by reason of pool development) submitted a letter informing the

Board of the operators' progress in commencing water injection. In July 1973 the Board, concerned by the possible occurrence of waste due to shrinkage losses before a water injection scheme commenced, called a hearing for the operators and interested persons to show cause why the pool production should not be restricted until a pressure maintenance scheme commenced.

4.0 MATTERS FOR CONSIDERATION

The Board believes the following issues should be considered:

(a) reasons for delay and the operators' plans for pressure maintenance, and

(b) relationship between shrinkage losses and date of initiation of a pressure maintenance scheme.

5.0 REASONS FOR DELAY AND THE OPERATORS' PLANS FOR PRESSURE MAINTENANCE

5.1 Views of Gulf

Gulf stated that the model depletion studies were delayed due to incomplete data on the pool extension to the south-east. Consequently Gulf stated unitization agreements and water injection commencement have been delayed. Gulf was of the view that water injection would commence before the spring of 1974.

5.2 Views of Samedan

Samedan stated that field operational problems due to the remoteness of the area and poor weather conditions, and extension of the south-eastern perimeter of the pool had delayed field testing, the model study and unitization agreements. Samedan stated that because of these delays commencement of water injection had been delayed. Samedan expressed the opinion that water injection would commence by March 1, 1974. It stated that all necessary physical facilities could be installed by the end of 1973 but that lack of unitization agreements might delay injection several more months.

5.3 Views of the Board

Although the Board recognizes the operational problems in the Meekwap area, it assumes that such problems were considered when the initial water injection target date of

January 1, 1973, was proposed by the operators and agreed to by the Board. The Board cannot accept that significant shrinkage losses should be permitted to occur as the result of delays due to operational problems.

6.0 SHRINKAGE LOSSES — PRESSURE MAINTENANCE RELATIONSHIP

6.1 Views of the Board Staff

Assuming a production rate of 5000 barrels of oil per day (BOPD) the Board staff estimated a pressure decline of 160 pounds per square inch (psi) per year would occur after February 1973. This rate was stated by the staff to be significantly higher than the rate of decline experienced between June 1972 when the pool bubble point was reached and February 1973. The Board staff contended that the increased rates of production experienced early in 1973 had accelerated the rate of pressure decline. Consequently, Board staff expressed the opinion that the pool production should be restricted to prevent shrinkage losses from occurring if delays in the implementation of a water injection scheme occurred.

The Board staff indicated that from examination of the gas-oil ratios (GOR's) of 20 individual wells over the period March 1973 to June 1973, a consistent increase of about 100 standard cubic feet per stock tank barrel (SCF/STB) for most of the wells was evident. Although four months production with increasing GOR's was not sufficient evidence in itself, the Board staff stated that, considering the accelerated rate of pressure decline and the further decrease in reservoir pressure below the pool bubble point of 2464 pounds per square inch gauge (psig), excess gas could be segregating out of the reservoir creating a trend of excess gas production. The Board staff used a solution GOR of 675 SCF/STB, taken from flash pressure-volume-temperature (PVT) data on the sample at the well in 3-20-66-15 W5 (hereinafter referred to as the 3-20 well).

Based on an estimated pressure decline of 160 psi per year and a production rate of 5000 BOPD, the Board staff calculated that total shrinkage losses of 300,000 STB will occur between June 1973 and June 1974. In its evaluation, the Board staff used a critical gas saturation of six per cent which was estimated to occur at an average reservoir pressure of 2300 psig. In response to questioning, the Board staff stated that the irreversible shrinkage losses would approximately be in the order of one-half the total shrinkage losses calculated.

The Board staff performed material balance calculations assuming steady state conditions, an initial oil in place of

56,000,000 STB, a solution GOR of 675 SCF/STB and other flash data from the sample from the 3-20 well. The staff calculations indicated incremental water drive indices (WDI's) in the order of 0.5 above the bubble point and in the order of 0.2 below the bubble point. The Board staff noted that a steady state system was used to calculate WDI's, although an unsteady state system was considered to exist. The Board staff concluded that there was an increased influence of free gas evolution and expansion as the pressure dropped below the bubble point, and this suggested that an increased portion of the pool depletion mechanism was that of a solution gas drive. If continued, this could, in the Board staff's opinion, result in a lower recovery than that currently assigned for the pool using a WDI of approximately 0.5.

Based on these considerations, the Board staff stated that to prevent losses in recovery until water injection had commenced, pool production should be restricted.

6.2 Views of Gulf

Gulf stated that over the period of February to June 1973 the average pool pressure in the Meekwap D-2 A Pool was declining at a rate of 170 psi per year based on the June 1973 pressure survey which showed an average pressure of 2348 psig at datum. Gulf, however, considered this pressure to be representative of only the area of maximum withdrawals and not a representative average pool pressure. Gulf contended that the August 3, 1973, average pool pressure of 2319 psig was consistent with its calculated pressure decline trend of 170 psi per year. Therefore Gulf stated that the recent high production rates have not accelerated the pressure decline.

Gulf expressed the opinion that there was satisfactory similarity between the pool average producing GOR and the flash GOR data from the PVT studies performed on the 8-25-66-16 W5M well and the 3-20 well, except during the months of May, June and July of 1973. Gulf based its comparison on an initial flash solution GOR of 580 SCF/STB. Gulf stated that the increased GOR's in the months of May, June and July of 1973 were merely a fluctuation in the monthly GOR and did not reflect the beginning of excess gas production generally experienced after reaching the critical gas saturation pressure.

Gulf stated that shrinkage losses would not occur until the pool pressure dropped below the critical gas saturation pressure. Gulf initially used an estimated critical gas saturation of five per cent in its model study of the Meekwap D-2 A Pool but could not obtain a satisfactory history match of pool performance. The applicant submitted that a reasonable history match of pool performance was obtained using a critical gas saturation of six per cent. Gulf stated that this saturation would occur initially in portions of the reservoir at a pool pressure of 2200 psig. Furthermore, Gulf contended that some areas of the reservoir would not experience this critical gas saturation until pressures had declined to about 1650 psig. Based on its model study, Gulf predicted that with the present production rates the pool pressure would not drop to the level of 1600 to 1700 psig until about mid-1975, at which time the volume of excess gas production would become significant.

Using the reservoir model, Gulf examined the impact on ultimate oil recovery that would be experienced by commencing water injection at three different times (July 1, 1973; January 1, 1974; July 1, 1975). In Gulf's opinion, the study indicated that the same ultimate recovery would be realized from the pool for each of the three times for commencement of water injection.

Gulf stated that shrinkage losses are included within the model calculations of ultimate recovery but are of such magnitude that they cannot be isolated, considering the error band of the model. Gulf's model study projected curves of ultimate recovery versus water-oil ratio (WOR) for the three cases to conditions representing average pool WOR's in the order of 4 to 6. Gulf then manually extrapolated these curves by a straight line to abandonment, which was considered to be at a WOR of 10.0. These curves showed, in Gulf's opinion, that significant shrinkage losses would not occur by delaying water injection to mid-1975.

Gulf stated that the Meekwap D-2 A Pool is made up of a good permeable layer with a tighter layer above and below the more permeable one. Gulf expressed the view that dropping the pressure before commencement of a water flood could create oil recovery benefits from the tighter layers of the reservoir by creating a driving force through gas expansion to displace some of the oil outward into the more permeable layer, which could then be swept efficiently by water. On these grounds Gulf contended that the pool production should not be restricted before water injection commences because only minor irreversible shrinkage losses would occur by continuing the present production rates of 4000 to 5000 BOPD even if commencement of injection were deferred until mid-1975.

Gulf stated that its steady state material balance calculations, which were based on an initial oil in place of 59,962,000 STB, a solution GOR of 580 SCF/STB and other flash PVT data from the two samples, indicate that the incremental WDI's at pool pressures below the bubble point pressure have remained steady at a level of approximately 0.5. These WDI's were also experienced at pressures above the bubble point pressure. Gulf concluded that this indicated that the increased pressure support in the pool due to gas evolution and expansion below the bubble point had not caused the WDI to decrease. Consequently, Gulf further concluded that the recent high production rates from the pool were not detrimentally affecting the support from the natural water drive. Gulf contended that if the drive indices were to change when the pool pressure dropped below the bubble point, then the parameters that were used to evaluate the hydrocarbon voidage and expansion were probably in error. Gulf expressed the belief that although an unsteady state system exists, a steady state material balance could be used to estimate reasonably accurate water drive indices.

6.3 Views of Samedan

Samedan stated that its latest pressure survey taken on eight wells, on August 3, 1973, showed an arithmetically averaged pool pressure of 2319 psig. Samedan also indicated that the average pressure using only the four wells that were surveyed on June 9, 1973, was 2322 psig.

Samedan expressed the view that the increase in pool GOR of 100 SCF/STB in May, June and July of 1973, was a normal short term fluctuation in GOR performance and was not a trend of increasing pool GOR's. Samedan indicated a variation of this magnitude had been observed previously in the pool history. Samedan also stated that the solution GOR was approximately 600 SCF/STB.

Samedan informed the Board that, in an effort to determine why the pool GOR jumped approximately 100 SCF/STB between April and May 1973, it examined production figures. Samedan found an error in the reported GOR in April due to the installation of a larger gas meter run at one of the batteries. When corrected, the pool GOR was estimated to be increased from a reported 500 SCF/STB to approximately 530 SCF/STB. This would, in Samedan's opinion, reduce the magnitude of the sudden fluctuation in pool GOR.

Regarding the conservation aspects of delaying commencement of water injection, Samedan stated that it supported Gulf's submission which contended that no decrease in the ultimate recovery of oil would occur due to continuing the present production rates of 4000 to 5000 BOPD and delaying commencement of injection to mid-1975.

6.4 Views of the Board

The Board agrees with Gulf that the pool pressure is declining at a rate of 170 psi per year with the present rate of production of 4000 to 5000 BOPD. Furthermore, the Board notes that this rate confirms the Board staff's estimate of 160 psi per year. Considering the June and August 1973 survey pressures of 2348 and 2319 psig at datum as representative arithmetically averaged pool pressures, the Board agrees with the Board staff that the rate of pressure decline has increased since February 1973 over the rate of decline experienced in the period between June 1972 and February 1973. The Board believes the increased production rates since about February 1973 have caused the accelerated rate of pressure decline.

The Board believes that the increased GOR's during the months of May, June and July 1973 do not positively indicate a trend of excess gas production due to gas segregation from the reservoir. In the opinion of the Board, the increased GOR's could be due to the currently increased production rates. Accepting Gulf's critical gas saturation of six per cent, occurring at an average pool pressure of 2200 psig at datum, the Board agrees that on average, excess gas production will begin to occur at that pressure level. However, in the opinion of the Board, excess gas production will commence before the average reservoir pressure reaches 2200 psig as parts of the reservoir will reach the critical gas saturation pressure before others, due to formation depth differentials and unsteady state effects.

The Board believes that irreversible shrinkage losses will occur if the pressure drops below the pressure of 2200 psig due to the loss of reservoir energy by the production of excess gas. It is the opinion of the Board that equally valid extrapolations of Gulf's model predictions of oil recovery might indicate that different total oil recoveries could be realized using different initiation dates for water injection. However the Board does not believe that Gulf's model prediction and extrapolation is of sufficient accuracy to determine the effect of shrinkage losses on ultimate recovery. The Board agrees with Gulf that decreasing the pressure may cause a driving force by the expansion of gas sufficient to displace some oil from the tighter layers into the more permeable layer so that it can be recovered by water flooding.

The Board agrees with Gulf and the Board staff that the system is an unsteady state system but that steady state material balance calculations are a reasonable basis to estimate the WDI of the pool. The Board considers that the difference in the Gulf and Board staff calculated WDI's below the bubble point is due to the different flash PVT data being used. However, the Board believes that whether the WDI is 0.5 or 0.2 is not a major concern. Rather, the Board's concern is that the pressure is continually dropping below the bubble point and is approaching the critical gas saturation pressure where it believes shrinkage losses will occur.

The Board estimates that if production continues at 5000 BOPD, irreversible shrinkage losses of some 50 MSTB will occur by May 1, 1974. If a pool production rate of some 3500 BOPD is assumed, the Board estimates that such losses would not occur over the period. Accordingly, the Board cannot agree with Gulf's contention that losses would be minimal if production were to be continued at 5000 BOPD until the spring of 1974. In the Board's view these losses are preventable and should be prevented, either by early commencement of pressure maintenance, or in the alternative, by imposing a period of reduced rates until water injection is commenced.

7.0 DECISION

The Board believes that significant conservation losses could begin to occur with the present rate of production of some 5000 BOPD after about January 1, 1974. The Board also believes that facilities necessary to commence water injection can be available by that date. As a further consideration, the Board recognizes a recent application submitted by Samedan on behalf of the Working Interest Owners of the Meekwap D-2 A Pool which specifies a date for commencement of water injection of "not later than April 1, 1974". Accordingly, it is the Board's decision that unless a scheme to pressure maintain the pool has commenced operation by January 1, 1974, the pool production shall be restricted commencing on that date to 3500 BOPD until such time as pressure maintenance is initiated.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig, P. Eng.
Vice Chairman

DATED at Calgary, Alberta
October 11, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-19
Application No. 7087

COMPULSORY POOLING - CAMPBELL FIELD

1. THE APPLICATION AND HEARING

Richard J. Churchill Limited applied pursuant to section 82 of The Oil and Gas Conservation Act for an order that all tracts within Section 22, Township 54, Range 25, West of the 4th Meridian be operated as a unit to permit the production of gas from the Basal Quartz Formation through the well, RICHFIELD O. D. CAMPBELL NO. 1, located in Legal Subdivision 6 of Section 22, Township 54, Range 25, West of the 4th Meridian.

No interventions were filed with respect to the application.

The application was heard on October 25, 1973 by the Board with V. Millard, J. I. Strong, P.Eng., and N.A. Macleod, Q.C. sitting.

Appearances

The following were represented at the hearing:

	Represented by	Abbreviation used in Report
Richard J. Churchill Limited	Richard J. Churchill	Churchill
Board Staff	F. G. Sorenson	

2. SUBMISSION OF APPLICANT

2.1 Attempts to Pool Voluntarily

Churchill submitted that an agreement to operate all tracts within Section 22 as a unit for the production of gas from the Basal Quartz sands could not be made on reasonable terms. In support of the application, Churchill submitted correspondence and reports of personal interviews with the mineral owners as evidence of the attempts to reach a voluntary pooling agreement.

2.2 Allocation of Production

Churchill proposed that the allocation of production and costs to each tract be on an acre/foot basis. Churchill stated that it would not matter to it to whom the royalty was paid. However based on geological control in the area, it considered that the allocation on an acre/foot basis would be more equitable than on an area basis.

3. VIEWS OF THE BOARD

3.1 The Board agrees with Churchill that a voluntary agreement to operate all of the tracts within the drilling spacing unit, as a unit cannot be made on reasonable terms.

3.2 The Board agrees that the allocation of production and costs on an acreage basis would be inequitable, and that the allocation should be on an acre/foot basis.

4. DECISION

The Board is prepared, with the approval of the Lieutenant Governor in Council, to order that all tracts in Section 22, Township 54, Range 25, West of the 4th Meridian, be operated by Churchill as a unit to permit the production of gas from the Basal Quartz Formation through the well, RICHFIELD O.D. CAMPBELL NO. 1, with the allocation to tracts of their shares of production and costs to be on an acre/foot basis, and subject to provisions for the payment of proceeds of production usual in such orders.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
December 3, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 73 - 20
Applications 7202 & 7278

Commingling of Production of Milk River and Medicine Hat Pools Alderson, Bantry and Princess Areas

1. THE APPLICATIONS AND HEARING

By Application No. 7202, Merland Explorations Limited applied under section 3.050 of the Oil and Gas Conservation Regulations for approval for the production of the Milk River, Medicine Hat and Second White Specks formations without segregation in the well bore in a portion of the Bantry and Princess areas. At the hearing the request for commingling the Second White Specks formation was withdrawn. The applicant also requested that the application be granted on a temporary basis and that an interim order be issued permitting commingling of the Milk River and Medicine Hat formations on the understanding that if the Board's decision was not in favour of the application the formations would be segregated.

By Application No. 7278, Alberta Eastern Gas Limited applied under section 3.050 of the Oil and Gas Conservation Regulations for approval for the production of the Milk River and Medicine Hat formations without segregation in the well bore in a portion of the Alderson, Bantry and Princess areas.

The applicants asked that the Board hear and consider the two applications concurrently.

The applications were heard on October 17, 1973, by the Energy Resources Conservation Board with D. R. Craig, P. Eng. and V. Millard sitting.

2. APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Alberta Eastern Gas Limited	A. D. Rogan, P. Eng. R. C. Horne	Alberta Eastern
Merland Explorations Limited	C. W. Lockwood P. H. Belliveau, P. Eng. P. Oley, P. Eng.	Merland
Many Islands Pipe Lines Limited	L. G. Ganne Mr. Naimish	Many Islands

	Represented by	Abbreviation Used in Report
Energy Resources Conservation Board	D. G. Pearson, P. Eng. C. W. Toews, C.E.T.	

Great Basins Petroleum Ltd. and Supertest Investments and Petroleum Limited were not represented at the hearing.

3. DEFINITION OF ISSUES

The Board considers the following to be the issues involved in considering the applications for commingling the Milk River and Medicine Hat pools:

(a) the need for commingling,

(b) the effect of commingling

  1. on the ultimate recovery of gas from each formation,

  2. on correlative rights within the areas of application, and

  3. on gas productive areas adjacent to and beyond the areas of application.

4. VIEWS OF ALBERTA EASTERN

Alberta Eastern submitted that exploitation of the Medicine Hat formation in the area of application is uneconomic if this formation is considered in isolation. Using a gas price of 28 cents per Mcf and a stabilized production rate of 100 Mcfd per well, a capital payout of 4.3 years was calculated for a well drilled and completed in the Medicine Hat formation. Alberta Eastern stated that the above calculation was optimistic since the current gas price is below 28 cents per Mcf and that the Medicine Hat formation cannot expect to produce at the stabilized rate for a period in excess of five years. By commingling the Medicine Hat formation with the primary producing formation such as the Milk River formation, Alberta Eastern estimated the payout at a stabilized rate of 100 Mcfd to be 1.8 years. Alberta Eastern calculated the payout would not be in excess of three years even after having regard for a decline in production rate. Alberta Eastern submitted that an alternative to the above approach would be to dually complete and segregate the Milk River and Medicine Hat formations, but that the added risks and operation problems associated with a dual completion would not economically justify depletion of the Medicine Hat in the area of application.

Alberta Eastern stated that recoveries from either formation would not be adversely affected by commingling the production from the two formations. It said that recoveries may in fact be improved by commingling since the two horizons are only marginally economic. Alberta Eastern commented that the application was for commingling of cased wells only since producing problems had been experienced in open hole Milk River completions. It stated that for the purposes of reserve determinations the formations could be considered to be one and that it would not serve a useful purpose to require segregation. It stated that for purposes of monitoring production it was prepared to segregate two or three wells per township. Alberta Eastern proposed that the group metering presently being utilized be continued for purposes of normal production measurement.

Alberta Eastern stated that it did not believe that commingling of the two formations would be desirable in all parts of Bantry, Princess, Medicine Hat, Alderson areas. Certain areas in both formations are known to contain water which could have a detrimental effect on ultimate gas recovery. In reply to questions at the hearing, Alberta Eastern agreed that a buffer zone adjacent to water-prone areas, where commingling would not be permitted, would be desirable. It stated that each application for commingling in a specific area should be treated on its own merits, having regard for the effects that such operations would have on recovery of gas, but that approval in principle should be granted for the entire area. Alberta Eastern submitted that a buffer zone of one to two miles around the water-prone areas would be adequate.

Alberta Eastern expressed the opinion that not every well would be commingled nor would wells necessarily have to be drilled on the same spacing. Alberta Eastern said that while the Medicine Hat formation is presently subject to a well density of one well per section more production performance was required before spacing units of less than one section could be considered. It submitted that on average the drilling density to the Milk River would be between 160 acres and 320 acres.

Alberta Eastern stated the problem of correlative rights of owners of vertically separated geological horizons would have to be resolved where ownership was not the same in the Milk River and Medicine Hat through a type of unitization or pooling agreement. Any correlative rights problems between adjacent or nearby tracts would be solved by suitable spacing regulations under The Oil and Gas Conservation Act.

5. VIEWS OF MERLAND

At the hearing Merland withdrew its request to commingle the Second White Specks formation with the Milk River and Medicine Hat formations. Merland stated that it had anticipated finding reserves in the Second White Specks formation but recent drilling had indicated that the formation does not contain gas. Merland also stated at the hearing that recent test data showed that it is economical to proceed with development of the Milk River formation separately. Furthermore, the Medicine Hat formation would be economical to develop separately in certain areas of the application. Merland submitted that commingling would enhance the economics in the area and would permit production of marginal gas which otherwise would be lost. It also stated that commingling would reduce the number and complexity of wells which would reduce the adverse effect on the environment of drilling and producing wells in the area.

Based on an average gas price of 26 cents per Mcf Merland calculated a payout period for four different cases of well completion and deliverability. The results are summarized below

Case	Method of Production	Rate of Production (Mcfd)	Payout Period (Years)
1	Single Completion of Milk River	100	6.94
2	Commingle Milk River and Medicine Hat	75/formation	6.33
3	Commingle Milk River and Medicine Hat	100/formation	5.05
4	Commingle Milk River and Medicine Hat	100 for Milk River 200 for Medicine Hat	3.8

Merland stated that the most probable case would lie somewhere between case 3 and case 4.

Merland agreed it would not be in the general interest to permit commingling over the entire Alderson, Bantry, Medicine Hat, Princess area because certain areas contain water in either the Milk River or the Medicine Hat formation. This water could have an adverse effect on ultimate recovery if commingling were permitted in its presence. Merland said that commingling should be approved in principle for the entire area. Merland did not believe that a buffer zone surrounding the water-prone areas was needed due to the low transmissibility of the Medicine Hat formation.

Merland stated that spacing of the two formations should be the same. Merland applied to the Board on October 15, 1973 for 160 acre spacing in both the Milk River and Medicine Hat formations for a substantial portion of the area of application for commingling. Merland did not believe that horizontal and vertical equity was a problem in its area of application, but in areas where this may be a problem it would have to be resolved by the operators. Merland did not believe that it was necessary to segregate certain wells for the purpose of production performance. It said that there would be a number of Milk River wells produced separately where it would not be economical to re-enter the well to deepen it to the Medicine Hat formation, and these wells could be used to assess the reservoir behaviour.

At the hearing Merland applied for an interim order to permit commingling of production in the wells in the area of application until a decision respecting the application was issued on the understanding that if the application was not granted the Milk River and Medicine Hat formations would be segregated.

6. VIEWS OF THE BOARD

The Board agrees with the applicants that commingling in the well bore of production from the Milk River and Medicine Hat formations would enhance the economics of development and production in the areas. It also agrees that commingling of these pools could result in the production of reserves that otherwise might not be developed. In view of the large areal extent of the Milk River and Medicine Hat formations and the possible occurrence of water production in certain areas the Board is of the opinion that commingling of these formations should be permitted in principle in the Alderson, Bantry, Brooks, Jenner, Johnson, Medicine Hat, Newell, Princess, Suffield and Verger areas, but that the desirability of commingling of production in any specific area must be considered on an individual application basis. The Board recognizes that the recovery of gas may be adversely affected by commingling of production in areas where either formation contains water and accordingly believes that a buffer zone adjacent to the potential water producing areas, where no commingling of production is to be permitted, is necessary. In view of the uncertainty of the occurrence of water production in the areas and the effective radius of drainage of the wells the Board believes that a buffer zone of at least two miles in width should be established between areas of commingling and areas of known water production. Where, in an area where commingling is occurring, a well produces water, the Board believes it should be advised immediately, the well should be immediately returned to segregated production and the operator should file with the Board within three months a report providing an analysis of the impact on ultimate recovery in the area and any proposed action.

The Board is of the opinion that, in zones of low productivity such as occurs in the Milk River and Medicine Hat formations, individual well performance history in each formation is desirable for the purpose of estimating pool reserves and recovery efficiencies and believes that at least one well in each quarter township, uniformly distributed over the area, should be maintained as a single zone completion for the purpose of monitoring production and pressure performance. Wells for this purpose, mutually agreeable to the Board staff and the applicant, could be selected at the time that application is made for the commingling of production in a specific area and should have regard for the distribution of ownership in that area.

The Board believes that correlative rights could be affected in the approved areas but agrees with Alberta Eastern that drainage between nearby wells would be controlled by spacing regulations. Problems due to differing ownership of gas rights in the same spacing unit would have to be resolved by the parties involved before commingling could commence in the spacing unit.

7. DECISION

The applications of Alberta Eastern and Merland are granted. The production from each of the Milk River and Medicine Hat formations in at least one well in each quarter township in the areas of application shall be maintained on a segregated basis for the purpose of monitoring production performance, the selection of the wells to be determined between the applicants and the Board staff.

In the event of the occurrence of water production in excess of water of condensation at any well where production is taken without segregation, the operator shall immediately advise the Board, immediately return the well to a segregated production basis and file with the Board within three months a report providing an analysis on the impact on ultimate recovery in the area and any proposed action.

Commingling in the well bore of production from the Milk River and Medicine Hat formations is approved in principle for the Alderson, Bantry, Brooks, Jenner, Johnson, Medicine Hat, Newell, Princess, Suffield and Verger areas, subject to the following:

1. Commingling shall be prohibited in a buffer zone of two miles width established between an area approved for commingling, and an area of known water production.
2. At least one well per quarter township shall be maintained in each of the Milk River and Medicine Hat formations on a segregated production basis for the purposes of production and pressure monitoring.
3. Before commingling of Milk River and Medicine Hat formations production is approved for any area beyond the areas that are of the subject applications,an application

for such approval must be made to the Board and each such application shall be considered on its own merits.

Order No. MU 96 has been issued reflecting this decision.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
December 14, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 73-21
Application No. 7310

SUSPENSION OF TARGET AREA REQUIREMENTS

MEDICINE HAT FIELD

1. THE APPLICATION AND HEARING

Great Basins Petroleum Ltd. applied pursuant to section 81, subsection (4) of The Oil and Gas Conservation Act for an order suspending the application of section 4.020, subsection (3) and section 4.070, subsection (2) of the Oil and Gas Conservation Regulations to wells either drilled or to be drilled within the Schuler-Medicine Hat Gas Unit for the production of gas from the Medicine Hat Sandstone Formation. The Schuler-Medicine Hat Gas Unit is in Townships 15, Ranges 1 and 2, West of the 4th Meridian.

An intervention was filed by Patio Petroleum Ltd. in opposition to the application.

The application was heard by the Energy Resources Conservation Board on December 4, 1973, with V. Millard, D. R. Craig, P. Eng. and N. A. Macleod, Q.C., sitting.

2. APPEARANCES

The following were represented at the hearing:

	Represented by	Abbreviation Used in Report
Great Basins Petroleum Ltd.	C.L. Franke, P.Eng. G. Dobson E.P. Webb, P.Eng.	Great Basins
Patio Petroleum Ltd.	J.B. McCaffrey, P.Geol. J.A. Dockery, P.Eng.	Patio
Energy Resources Conservation Board	R.W. Edgecombe, P.Eng. R.D. Florence G.J. DeSorcy, P.Eng. I.F. Taylor, E.I.T.	Board Staff

3. SUBMISSION OF APPLICANT

Great Basins submitted that relief from the present one section drilling spacing units was necessary in the Schuler-Medicine Hat Gas Unit in order to increase deliverability and permit an ultimately higher recovery of the reserves in place. The original application applied to the entire unit area which contained some partial drilling spacing units. In response to questioning by the Board staff, the applicant agreed to amend its application so that the area of application would contain only whole drilling spacing units within the unit area.

Great Basins also agreed, after questioning by the Board, to amend its application to include a request for suspension of the provisions of section 4.070, subsection (2) of the Oil and Gas Conservation Regulations to wells drilled or to be drilled in the unit area.

4. SUBMISSION OF INTERVENER

Patio Petroleum Ltd. objected to the application on the grounds that, because the unit "windowed" its land on three sides, unequitable drainage would occur if the application were granted. It further contended that Great Basins was denying Patio its right to a share of production by refusing to accept gas from Patio's well, DARLING ET AL MEDHAT 6-30-15-1. Patio further requested that evidence presented in its Application No. 7405, which requested the Board to declare Great Basins to be a common carrier, be accepted as evidence in its intervention to the subject application.

5. FINDINGS OF THE BOARD

The Board agrees with the applicant that the proposed increase in well density will improve recovery from the reservoir.

The Board recognizes that Great Basins had the alternative remedy of applying for a change in spacing and considers that Patio similarly could apply for a spacing order which would permit the drilling of wells in the lands of concern to Patio, that is, Sections 30 and 31, both in Township 15, Range 1, West of the 4th Meridian, to a density equal to that which Great Basins proposes in the subject application. The Board sees no barrier to the granting of such an application.

The Board finds that Great Basins' application, as amended, would not necessarily lead to inequitable drainage of Patio's reserves. The Board further finds that the type of evidence required to be submitted to support Application No. 7405 would not be relevant to the subject application.

6. DECISION

The Board grants the application, as amended, of Great Basins, subject to the following provisions:

1. A well drilled or to be drilled for the production of gas from the Medicine Hat Sandstone Formation shall not be located closer to the unit boundary than 1300 feet, and

2. A well drilled or to be drilled for the production of gas from the Medicine Hat Sandstone Formation within the area of application shall not be located less than 2600 feet from any other well producing from the same formation.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
December 31, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 74-1
Application No. 7254

APPLICATION FOR PERMIT TO CONSTRUCT A GAS PIPE LINE FROM HOMEGLEN-RIMBEY AREA TO BONNIE GLEN AREA

1. THE APPLICATION AND HEARING

Northwestern Utilities Limited applied pursuant to Part 2 of The Pipe Line Act for a permit to construct approximately 24 miles of 24-inch gas pipe line extending from the Homeglen-Rimbey Area to the Bonnie Glen Area.

The hearing was originally scheduled for October 16, 1973 but was adjourned at the request of Northwestern Utilities Limited, and as agreed to by the interveners, to provide Northwestern Utilities Limited with time to prepare additional information requested by The Alberta Gas Trunk Line Company Limited. The application was heard on December 13, 1973 by the Energy Resources Conservation Board with D R. Craig, P. Eng., V. Millard, and G. J. DeSorcy, P. Eng. sitting

Upon the completion of the filing of evidence, of cross-examination and of argument, there being no objections to the application and the Board being satisfied with it, the Board orally advised the applicant that it would grant the application through the issuance of the requested pipe line permit.

2. APPEARANCES

The following appeared at the hearing:

	Represented by	Abbreviation Used in Report
Northwestern Utilities Limited	B. V. Massie, Q.C. T. Mayson, Q.C.	Northwestern Utilities
The Alberta Gas Trunk Line Company Limited	G. R. Forsyth, Q.C.	Trunk Line
Alberta and Southern Gas Co. Ltd.	F. G. Homer	Alberta and Southern
TransCanada PipeLines Limited	E. W. H. Mallabone	TransCanada

	Represented by	Abbreviation Used in Report
The City of Edmonton	H. F. Wilson	The City of Edmonton
Board Staff	N. A. Macleod, Q.C. D. G. Pearson, P.Eng. E. C. Fox, P.Eng.	

Witnesses for the applicant were J. H. Pletcher, P. Eng. and D. L. Weiss, P. Eng.

3. VIEWS OF NORTHWESTERN UTILITIES LIMITED

The applicant stated that the purpose of the proposed gas line is to provide high pressure gas for miscible flood schemes, to assist in meeting Northwestern Utilities' peaking requirements during the winter season, and to provide a back up emergency supply in case of failure of a major supply source on Northwestern Utilities' existing system. At the hearing the applicant amended the application by deleting from its requirements gas for the purpose of miscible flood, but indicated that others may wish to use the line to transport gas for miscible flood purposes.

Northwestern Utilities submitted details of the design capacity of its existing integrated system and its estimates of the peak day demands for gas for a six-year period up to and including the winter of 1978-79. The study indicated a deficiency with the existing system in 1974-75. The proposed pipe line could readily be extended to the Edmonton area to meet long term future requirements and would increase the existing system capacity so that the requirements could be met until 1975-76.

Northwestern Utilities investigated other alternatives such as adding compression or looping existing gas lines but concluded that the proposed pipe line would provide the most economical method of assuring its future gas requirements.

In response to questioning Northwestern Utilities indicated it would be willing to negotiate the matter of compensation if the proposed pipe line should result in unused capacity in the Trunk Line and TransCanada systems, and stated that, if the parties could not agree on the compensation, then the matter could be referred to the Public Utilities Board for resolution.

4. VIEWS OF THE INTERVENERS

None of the interveners submitted any evidence respecting the need for or design of the pipe line and intervened only for the purpose of cross-examination and argument. TransCanad expressed through its cross-examination some concern regarding the effect that unused pipe line capacity would have on TransCanada and other gas purchasers.

5. VIEWS OF THE BOARD

The Board is satisfied as to the need for and design of the pipe line.

With respect to the matter of compensation as a result of any unused capacity created in the Trunk Line and TransCanada systems which might develop, the Board agrees with Northwester Utilities that this is a matter that is outside the provisions of The Pipe Line Act and that should not concern this Board.

6. DECISION

Permit 15021 for the subject application was issued to Northwestern Utilities on December 14, 1973.

ENERGY RESOURCES CONSERVATION BO

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
January 4, 1974

ENERGY RESOURCES CONSERVATION BOARD

Decision No. 74-2
Application No. 7317

SULPHUR RECOVERY AND AIR POLLUTION CONTROL AT THE JUMPING POUND GAS PLANT

1. THE APPLICATION AND HEARING

Shell Canada Limited applied under section 38, subsection (1), clause (b) of The Oil and Gas Conservation Act for certain amendments of Board Approval No. 1393 respecting a scheme for the processing of gas produced in the Jumping Pound Field, Sarcee Field, and Jumping Pound West Field, at a plant located in the North-west quarter of Section 13 and the South-west quarter of Section 24, Township 25, Range 5, West of the 5th Meridian. The amendments requested are:

(a) to increase the minimum calendar quarter year sulphur recovery efficiency from 93.5 per cent to 95.0 per cent,

(b) to decrease the approved maximum daily sulphur dioxide emission from 53.7 long tons to 53.0 long tons,

(c) to increase the approved maximum half hour sulphur dioxide emission from 1.12 long tons to 2.0 long tons,

(d) to increase the incinerator stack height from 225 feet to 335 feet, and

(e) to increase the emergency flare stack height from 146 feet to 300 feet.

Shell proposed that the heights of the new stacks be calculated using a potential flow model developed by Western Research and Development Ltd. rather than the standard method employed by the Alberta Department of the Environment and the Board.

The application was heard at the offices of the Energy Resources Conservation Board, Calgary, on November 23, 1973 by Examiners J. A. Bray, P. Eng., E. R. Brushett, P. Eng., and H. J. Webber, P. Eng.

There were no interveners respecting the application.

2. APPEARANCES

The following appeared at the hearing:

	Represented by	Witnesses	Abbreviation Used in Report
Shell Canada Limited	J.E. Klinck	W.R. Grieff, P.Eng. R.L. Piche, P.Eng. J.A.W. Sandercock, P.Eng. M.D. Winning, P.Eng. D.M. Leahey (of Western Research and Development Ltd.) R.D. Rowe, P.Eng. (of Western Research and Development Ltd.)	Shell
Department of the Environment	R.P. Angle S.L. Dobko, P.Eng. R. Stetson, P.Eng.		Department
Board Staff	R.B. Dunbar, P.Eng.		Board

3. BACKGROUND

Approval No. 1393 for the Jumping Pound Plant permits processing of up to 249 million cubic feet per day (MMcfd) of raw gas and condensate containing up to 14.1 MMcfd of hydrogen sulphide (equivalent to approximately 530 long tons per day (LTD) of sulphur). During each calendar quarter it requires the recovery in the form of elemental sulphur of not less than 93.5 per cent of the sulphur contained in the gas delivered to the plant. The approval permits the emission of up to 53.7 LTD of sulphur dioxide (SO_2), or 1.12 long tons (LT) in any half hour period, to the atmosphere from the incinerator stack. The incinerator stack is 225 feet in height and the plant emergency flare stack is 146 feet in height.

Energy Resources Conservation Board Informational Letter No. IL 71-29 sets out minimum sulphur recovery efficiency guidelines for gas processing plants in Alberta. The guidelines require that a plant processing acid gas of average quality and 400 to 1000 LTD of sulphur recover from 95 to 98 of the sulphur contained in the raw gas delivered to the plant. The informational letter requires that existing plants be upgraded in accordance with the guidelines by January 1, 1975, unless exemption from the prescribed recovery levels is granted by the Board. After being advised by Shell that the Jumping Pound Plant would be upgraded to meet the requirements of the guidelines, the Board advised Shell by letter dated August 14, 1972 that the appropriate recovery requirement for the Jumping Pound Plant would be 95.0 per cent, to be achieved by January 1, 1975.

A matter related to the sulphur recovery efficiency to be achieved at the plant is the adequacy of the incinerator stack used to discharge the unrecovered sulphur to the atmosphere as sulphur dioxide. Board staff calculations, using the Pasquill equation, indicate that emissions from the existing stack could cause a maximum SO_2 concentration of 2.2 parts per million (ppm) at ground level at the top of Copithorne Ridge located one mile east of the plant. This is far in excess of the Provincial allowable maximum half hour average SO_2 concentration at ground level of 0.20 ppm, the design requirment for stacks. The inadequacy of the existing stack has been demonstrated by the results of Shell's continuous monitoring of air quality on the ridge. The monitoring has indicated that on 24 occasions the half hour average SO_2 concentration at ground level has exceeded 0.20 ppm in the period January 1, 1973 to October 31, 1973. The maximum detected half hour average SO_2 concentration during this period was 0.77 ppm. However, on this occasion wind data were not available to indicate definitely that the SO_2 originated from the Jumping Pound Plant. All other readings were below 0.36 ppm. The nearest other significant source of SO_2 emissions in the area is located approximately six miles to the north-west so that little plume overlap would be expected to occur, and it is likely that most of the readings resulted from the Jumping Pound Plant operation.

In order to meet the requirements of Informational Letter No. IL 71-29 and reduce sulphur dioxide concentrations at ground level to acceptable levels, Shell filed the subject application for the aforementioned amendments to Board Approval No. 1393.

4. DEFINITION OF ISSUES INVOLVED

The examiners consider the issues to be:

(a) Sulphur Recovery Efficiency - the adequacy of the proposed modifications to achieve the 95.0 per cent sulphur recovery requirement,

(b) Sulphur Dioxide Emission Rates - the requested change in daily maximum and half hour maximum sulphur dioxide emission rates,

(c) Dispersion Calculation Method - the method of calculating ground level sulphur dioxide concentrations at Jumping Pound,

(d) Incinerator and Flare Stack Adequacy - the adequacy of the proposed new incinerator stack and flare stack.

5. SULPHUR RECOVERY EFFICIENCY

5.1 Views of the Applicant

Shell stated that the 95.0 per cent sulphur recovery required by January 1, 1975 would be achieved with the existing sulphur recovery facilities through continuation of a plant improvement and modification program initiated in the latter part of 1972. Shell stated that the modifications completed to date include:

(a) Increased stability of sulfinol plant operations.

(b) Reduction of the hydrocarbon content of the sulphur plant feed gas.

(c) Addition of combustion air trim valves to the sulphur plant air/acid gas ratio control system.

(d) Improvements to gas analysers and meters in the sulphur plant control system.

(e) Improved recycle gas compressor operation.

Other modifications presently underway include:

(a) Addition of checkerwalls to the sulphur plant reaction furnaces.

(b) Reduction in sulphur condenser outlet temperatures.

(c) Additional processing of recycle gas.

If these modifications prove to be insufficient Shell stated that the following modifications are under consideration for 1974:

(a) Improved air blower speed control.

(b) Automatic sulphur plant temperature control.

(c) A third catalyst stage for Sulphur Plant No. 2 (Sulphur Plant No. 1 is presently shut down and Plants No. 3 and 4 are three stage units).

Shell expects that modifications beyond those described above would not be necessary to improve recovery to the 95.0 per cent level.

It submitted the recovery efficiencies reported on the sulphur balance reports and stated that these results indicate that the required recovery will be achieved by January 1, 1975. Sulphur balance report quarterly recoveries in 1971, 1972, and for the first three quarters of 1973 ranged from 93.9 per cent to 95.3 per cent and increased from an average of 94.7 per cent in 1971 to 94.9 per cent averaged over the first three quarters of 1973.

5.2 Views of the Examiners

The examiners agree with Shell's opinion that the required 95.0 per cent recovery can be achieved with the existing facilities and the plant modification program being followed. This view is substantiated by the success indicated to date on the sulphur balance reports and by incinerator stack survey results. The results of 11 stack surveys carried out during the period January 1, 1971 to September 19, 1973 indicate sulphur recovery efficiencies in the range 93.6 to 95.9 per cent. The arithmetic average recovery from the stack survey results was calculated to be 95.0 per cent.

On the basis of Shell's evidence, the examiners expect the average quarterly recovery to increase to 95 per cent before the end of 1974.

6. SULPHUR DIOXIDE EMISSION RATES

6.1 Views of the Applicant

Shell requested that the maximum daily sulphur dioxide emission rate for the incinerator stack be set at 53.0 LTD and that the maximum half hour sulphur dioxide emission be set at 2.0 LT (equivalent to an emission rate of 96.0 LTD). The requested daily maximum SO_2 emission of 53.0 LT was calculated from the maximum sulphur inlet rate of 530 LTD and the future minimum quarterly sulphur recovery efficiency of 95.0 per cent. The requested half hour maximum sulphur dioxide emission of 2.0 LT was that calculated by Shell to result in a maximum ground level SO_2 concentration of 0.20 ppm at the top of Copithorne Ridge using the potential flow assumption and the proposed 335 foot incinerator stack height.

In reply to questioning, Shell stated that it had not reviewed plant operating records to determine if half hour emissions as high as 2.0 LT had actually occurred in the past. The bases for making the request for such a high half hour emission were the result of the stack design calculation, and the need for plant operating flexibility.

6.2 Views of the Department

Department staff concur with the views of the examiners expressed below with respect to this aspect of the application.

6.3 Views of the Examiners

The examiners are of the view that the 53.0 LTD daily maximum rate proposed by Shell has been determined correctly using the accepted method of calculation, and would be the appropriate sulphur dioxide daily emission limit for the plant.

With respect to the half hour sulphur dioxide emission limit, the examiners reviewed the sulphur balance reports for the Jumping Pound Plant for the first eleven months of 1973 to determine actual daily maximum half hour emissions which have occurred in the past. During this period maximum half hour sulphur dioxide emission rates were reported for 323 of 334 days. The daily maximum half hour emission exceeded 1.10 LT (53.0 LTD) on 40 of the 323 days. On five of the days the maximum half hour sulphur dioxide emission was more than 40 per cent over 1.10 LT or over 1.55 LT. The highest reported half hour emission was 1.88 LT.

The above data indicate that a maximum half hour sulphur dioxide emission limit higher than 1.10 is required but that the limit need not be as high as 2.0 LT. The examiners note that 98.5 per cent of the readings were within a half hour emission 40 per cent over 53.0 LTD or a half hour value of 1.55 LT. A 40 per cent overage is that proposed by the Government for general use as a stack design criterion as a result of discussions at the Alberta Industry Government Sour Gas Environmental Committee meetings.

In view of the historical emission data, the proposal arising from the previously mentioned Industry-Government committee meetings, and the fact that future emissions should be lower than past emissions due to increasing sulphur recovery efficiency, the examiners are of the view that the half hour sulphur dioxide emission limit should be set at 1.55 LT.

7. DISPERSION CALCULATION METHOD

7.1 Views of the Applicant

In view of the unique topography of the area, Shell proposed that the new stacks be designed using a simple potential flow model to predict the height of the "streamline" over Copithorne Ridge, directly east of the plant. The "streamline" is the mean path followed by air passing the top of the stack under prevailing conditions. The required stack height would then be determined by the usual method recommended by the Alberta Department of the Environment which uses three-quarter of the Bousanquet-Carey-Halton plume rise and Pasquill's dispersion coefficients for a neutral atmosphere. The constant elevation streamline would be replaced by the calculated potential flow streamline over the terrain for calculation purposes.

Shell proposed to design the stacks using calculations on Copithorne Ridge, rather than the other hills north, north-west, and west of the plant. This is because westerly winds occur most frequently, the majority of the high monitored concentrations have occurred on Copithorne Ridge, and calculations using the standard design method also indicate that the highest concentrations would occur on Copithorne Ridge.

Shell acknowledged that the potential flow approach cannot possibly be a true model for the turbulent atmospheric boundary layer because it assumes irrotational inviscid flow. Shell stated, however, that potential flow does nonetheless predict some of the gross characteristics of the flow around an obstacle and argued that potential flow is assumed in the current standard techniques for calculating dispersion over flat terrain, because the wind velocity profile is assumed to be uniform.

For the Jumping Pound Plant situation Shell assumed that the air flow is two dimensional, i.e., that Copithorne Ridge is infinitely long with a uniform cross section. It was further assumed that the ridge could be approximated by a triangular cross section on flat terrain and that the centre line of the plume would be perpendicular to the axis of the ridge. With these assumptions the potential flow equations were solved to determine the location of the flow streamlines with respect to terrain. A numerical solution involving the finite element technique was employed to calculate the elevation of the plume streamline above the top of the Copithorne Ridge as a function of stack height. These results were then used to determine the stack height necessary to achieve a calculated maximum ground level SO_2 concentration of 0.20 ppm.

The validity of the potential flow technique was evaluated using a helicopter survey to determine the location of the actual plume streamline, relative to the top of the ridge, under present operating conditions. Vertical cross sections of the atmosphere downwind of the plant were sampled along three flight paths approximately parallel to the ridge. The three flight paths were:

(a) over the base of the ridge on the upwind side,

(b) over the top of the ridge, and

(c) over the base of the ridge on the downwind side.

Sampling was carried out on five separate days in November, 1972. The range of wind speeds encountered was 20 to 40 feet per second. During all tests the wind direction was from the stack toward the highest point on the ridge. The atmospheric lapse rate was near neutral during each of the tests. The plume was sampled using a fast response high sensitivity SO_2 analyser and sampling train mounted in the helicopter. The centre line of the plume at a given cross section was calculated from the helicopter survey results.

The helicopter survey indicated that at the lower wind speeds the plume lifts high into the air well clear of the ridge, while at the higher wind speeds the plume flows almost parallel to the terrain. Shell isolated the topographical effect from the observed results by subtracting the calculated plume rise from the observed plume heights. Shell found that the location of the wind flow streamline predicted using the potential flow numerical model correlated with the observed streamline at the higher wind speeds.

To further test the validity of the potential flow model, Shell determined streamlines for the true cross section using an electrical conducting paper analog technique. This technique showed streamlines slightly higher over the ridge than in the numerical solution, indicating that the numerical solution was conservative.

Based on the results presented, Shell concluded that the potential flow model provides a satisfactory method of evaluating the effect of the terrain on the plume for stack design calculations. It argued that this technique yields a more realistic height than assuming the terrain has no influence on plume behaviour and calculating ground level SO_2 concentrations accordingly.

The application of the potential flow model to the Jumping Pound Plant to determine the required incinerator and flare stack heights is discussed further in Section 8 of this report.

7.2 Views of the Department

Department staff and the examiners have jointly considered Shell's proposal respecting the dispersion calculation method proposed for design of the two new stacks at the Jumping Pound Plant. The Department and the examiners are in agreement respecting this matter. The views of both the Department and the examiners are therefore set out as views of the examiners in the following section of the report.

7.3 Views of the Examiners

The stack design method proposed by Shell has been thoroughly examined and compared with other methods of predicting maximum ground level sulphur dioxide concentrations. The examiners recognize the deficiencies in the standard technique normally employed in Alberta for stack design. However, they still believe that this technique provides a simple and reasonably reliable way of determining stack heights and should continue to be employed in normal circumstances. The examiners consider the Jumping Pound situation to be a special case due to the age of the plant, the imminent decline in sulphur plant throughput, and the topography unique to the area. This warrants consideration of a departure from the standard calculation method. The views of the examiners respecting the potential flow technique proposed by Shell follow.

As indicated by Shell, potential flow theory assumes that the fluid in motion is incompressible, irrotational and inviscid. Only the first of these conditions is reasonably well satisfied in the atmospheric boundary layer. The second is violated by the presence of strong wind shear in the surface layer; the third, by the fact that air does have viscosity.

Shell proposed that potential flow theory be applied to the streamlines at physical stack height. There is considerably less justification for this than there is for applying the technique to higher regions of the atmosphere, where boundary effects are not so dominant. At low elevations this approach must be regarded as crude. However, as pointed out by Shell, the standard diffusion model employed in Alberta also makes implicit use of potential flow by assuming a uniform wind profile. The examiners believe, however, that through attempting to account for the effect of terrain on the wind flow over Copithorne Ridge, the proposed approach may more closely approximate the real situation than the standard diffusion model.

The proposed potential flow model can provide a valuable tool at the Jumping Pound Plant; however, because of the assumption that the wind flow is irrotational and inviscid, verification of the potential flow model is critical to its application.

Shell expressed the view that the helicopter survey and the electrical conducting paper analog technique verified the model developed. The examiners note that the current flow through the electrical analog satisfies the Laplace equation and behaves in accordance with potential flow theory. This technique therefore can only be used to verify the accuracy of the numerical solution to Laplace's equation and not to test the effect of the assumptions that the flow is irrotational and inviscid. The only test of these assumptions is the helicopter survey.

Shell proposed that potential flow theory be applied to predict the position of a streamline passing through the top of the stack. Presumably this would be the path followed by an effluent experiencing no rise whatsoever. Verification was performed by subtracting the calculated plume rise from the observed plume centre line to obtain this "stack streamline". There are two weaknesses in this procedure:

(1) Topography may influence the plume rise, in which case subtracting the plume rise as calculated for flat terrain would not isolate the effects of topography. The location of the "stack streamline" could, therefore, be in error.

(2) The calculated position of the "stack streamline" depends on the formula used to calculate the plume rise. For example, away from the source the Briggs formula predicts a higher rise than the Bousanquet-Carey-Halton formula used by Shell. The subtraction of this larger rise would place the "stack streamline" closer to the ridge.

The examiners believe that the helicopter survey provides some verification of Shell's potential flow model for the atmospheric stability and wind conditions under which testing was carried out. However the examiners are not confident that the helicopter survey results are sufficiently accurate to conclusively verify the potential flow model. The scatter of data points and the lack of a pollutant material balance along each flight path make it difficult to place complete confidence in the results. The examiners conclude that the results of calculations using other diffusion models must also be considered in determining the stack heights for the Jumping Pound Plant and that insufficient study has been carried out to base the stack requirements on the potential flow model alone.

One consideration that confirms the examiners' views in this regard results from a review of air quality monitoring data for the plant. This review indicated that most of the violations of the air quality standards recorded during 1973 occurred with wind speeds less than 10 miles per hour. Shell's potential flow model predicts the highest concentrations under high wind speed conditions and therefore may not be valid for the atmospheric conditions under which violations have been recorded.

The examiners' review of the monitoring data also indicates that some violations were detected at the monitor north-west of the plant on Crawford Plateau. The examiners do not believe that Shell investigated other directions satisfactorily. However the examiners are satisfied that because violations at the plateau have been less frequent, because the prevailing winds blow toward Copithorne Ridge, and because the observed and calculated maximum concentrations on Copithorne Ridge exceed those for the plateau, only calculations carried out for the top of Copithorne Ridge need be considered in the design of stacks.

The examiners' views respecting the adequacy of the proposed new incinerator stack and flare stack are given in Section 8 of the report.

8. INCINERATOR AND FLARE STACK ADEQUACY

8.1 Views of the Applicant

Shell proposed to replace the existing 225 foot incinerator stack with a new stack 335 feet in height and to replace the existing 146 foot flare stack with a new stack 300 feet in height. Both stacks would be of steel construction and supported by guy wires. The height of both stacks was determined using the potential flow model to calculate the height of the flow streamline above Copithorne Ridge, three quarters of the Bousanquet-Carey-Halton plume rise, and the Pasquill dispersion coefficients for neutral stability.

Shell calculated that at a sulphur dioxide emission rate of 53.0 LTD from the proposed 335 foot incinerator stack the maximum ground level SO_2 concentration on Copithorne Ridge would be 0.11 ppm. A maximum half hour sulphur dioxide emission of 2.0 LT would result in a maximum calculated ground level SO_2 concentration of 0.20 ppm. Both results are within the Provincial calculation standard of 0.20 ppm. Shell stated that calculated ground level concentrations at other locations in the plant vicinity would be below the concentrations calculated for Copithorne Ridge.

Shell stated that increasing the height of the stack beyond 335 feet would substantially increase its cost. It stated that a 335 foot stack can be erected with a single lift while a higher stack would require multiple lifts and joining of the individual sections during erection. Shell stated that the cost of the two stacks would be approximately $750,000.00. It is estimated that increasing the height of the incinerator stack by 25 feet to a total height of 360 feet would increase the cost by approximately $100,000.00.

Shell proposed that the flare stack be 300 feet in height and that the schedule of fuel gas addition to sour gas flared be based on the potential flow model. Its calculations using the potential flow model showed that a 300 foot flare stack would have a 200 foot streamline elevation above the top of Copithorne Ridge. Shell therefore proposed to construct a 300 foot stack and utilize the fuel gas addition schedule that would normally be used for a 200 foot stack located in flat terrain. The fuel gas addition schedule would accommodate any condition of emergency flaring that could occur at the plant for all operating conditions up to and including full throughput.

8.2 Views of the Department

The Department and the examiners co-operatively examined this aspect of the application. The views of the examiners expressed below therefore also reflect the views of the Department.

8.3 Views of the Examiners

As stated in Section 7 of the report the examiners believe that diffusion models other than just the potential flow model proposed by Shell must be considered to determine the adequacy of proposed new incinerator stack and flare stack. The examiners therefore calculated ground level sulphur dioxide concentrations using several techniques as described below.

Calculations were first carried out using the standard diffusion model and employing the full height of Copithorne Ridge. The examiners recognize that this model assumes the air flow is unaffected by the terrain and is therefore not realistic in this regard. Assuming a maximum half hour sulphur emission of 1.55 LT, this model indicated that an incinerator stack height of 505 feet would be necessary to achieve a maximum calculated ground level sulphur dioxide concentration of 0.20 ppm on Copithorne Ridge. Using the same model but considering only half the height of Copithorne Ridge the required stack height was indicated to be 360 feet.

The examiners carried out further calculations using the three dimensional numerical model of Intercomp Resource Development and Engineering Ltd. This model indicated that at a maximum half hour sulphur dioxide emission of 1.55 LT, the maximum sulphur dioxide concentration at the top of Copithorne Ridge would be 0.22 ppm with the proposed incinerator stack, and that a stack slightly higher than 335 feet would be required. This model indicated that maximum sulphur dioxide concentrations would occur at low wind speeds under stable atmospheric conditions. The number of cases investiated with the Intercomp model was limited. Therefore, it is not known whether higher concentrations would have been predicted under different atmospheric conditions. Further, because only a minimal amount of history matching was carried out with the model, the results cannot be fully recognized.

An estimate of expected maximum ground level sulphur dioxide concentrations was also made using the results from the standard diffusion model and from past monitoring. The standard diffusion model indicates that ground level concentrations on Copithorne Ridge would be reduced by 50 per cent assuming full hill heights, or by 70 per cent assuming half hill heights, through installation of the proposed 335 foot incinerator stack. Using the average of these two values, it is indicated that a reduction of 60 per cent in ground level sulphur dioxide concentrations would occur, or that past concentrations below 0.50 ppm would have been below 0.20 ppm had the proposed 335 foot stack been in operation instead of the existing 225 foot stack. During 1973 all but one of 33 violations of the half hour sulphur dioxide standard of 0.20 ppm were below 0.50 ppm. The rough evaluation described in this paragraph therefore indicates that the proposed 335 foot stack would be adequate, as essentially none of the past violations would have occurred.

In summary, the examiners note that there is considerable variation in the ground level sulphur dioxide concentrations predicted using the various calculation techniques and that there are varying degrees of uncertainty associated with each. There is some indication that the proposed 335 foot stack may not be entirely adequate; however, the examiners believe that unless very extensive additional studies are carried out it would not be possible to further refine the stack design method. By way of compensation for this indicated possible deficiency the examiners recognize that Shell is operating three continuous air quality monitors in the plant vicinity from which measured concentrations are telemetered to the plant control room. This system enables the plant operators to take corrective action whenever measured concentrations approach the maximum permissible levels. Having regard for the monitoring system, the examiners conclude that the 335 foot proposed stack height should be approved on the basis of the conditions outlined in Section 9 of this report.

In regard to the proposal to install a new flare stack 300 feet in height, the examiners carried out calculations similar to those described above for the incinerator stack and concluded that a similar reduction in ground level sulphur dioxide concentrations would occur. The examiners also believe that the proposed flare stack should be approved subject to the conditions outlined in Section 9 of the report.

The examiners note that compliance with the Provincial ambient air quality standards would continue to be Shell's ultimate responsibility. Approval of the subject application by the Board and the Department would not relieve Shell of this responsibility. In the event that an unacceptable number of violations of the standards occurred after the new stacks were installed, the Board and the Department would require some change in the plant operation, such as a reduction in the sulphur dioxide emission limit or a further extension of the stacks. In this regard Shell may wish to provide for the possibility of a future extension of the stacks in the stack design.

The examiners wish to emphasize that their method of evaluation of stack adequacy at the Jumping Pound Plant is limited to this specific case only. The examiners have accepted the proposal in this case based on the following considerations:

(a) Extensive past monitoring data and wind distribution data were available to assist in the evaluation of the various diffusion models.

(b) Sulphur production and plant sulphur dioxide emissions will begin to decline in the near future.

(c) A further slight decline in emissions is expected as a result of further improvement in the sulphur recovery efficiency.

(d) A study of the effect of terrain on windflow unique to the Jumping Pound area has been carried out.

(e) Air quality monitoring and the use of telemetering facilities will be continued to provide back-up emission control.

(f) No recent complaints of the plant operations have been received.

The examiners believe that the standard diffusion model should continue to be employed for stack design until a better general method is devised. Some deviation from this model may be justified for other existing plants where peculiar circumstances exist. However, the examiners believe that any proposed deviation should be well justified. Proposed departures from the standard diffusion model for new plants would have to be extremely well justified.

9. RECOMMENDATIONS

The examiners recommend that

(a) The application be granted in part as follows:

- (i) The sulphur recovery efficiency to apply after January 1, 1975 be set at 95.0 per cent.
- (ii) The daily sulphur dioxide emission limit be set at 53.0 LT.
- (iii) The proposed 335 foot incinerator stack height and 300 foot flare stack height be approved.

(b) The half hour sulphur dioxide limit be set at 1.55 LT.

(c) The operation of the three station continuous monitoring network be continued at the discretion of the Department until experience indicates such operation to be unnecessary.

(d) Shell be required to continue the plant operating procedure which specifies that corrective action be taken whenever the measured sulphur dioxide concentration approaches the standard.

(e) A reduction in the emission limit, extension of the stacks, or other change in the plant operation would be required if an unacceptable number of violations of the Provincial ambient air quality standards continues to occur after installation of the new stacks

(f) A report summarizing plant operations and monitoring results be filed with the Board and the Department approximately one year after the new stacks have been placed in operation. Alternatively this information could be included in the annual report required by the Department if it is more convenient to do so.

10. BOARD DECISION

The Board adopts the recommendations of the examiners and will issue an amendment of approval accordingly.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
February 5, 1974

ENERGY RESOURCES CONSERVATION BOARD

Decision 74-3
Proceeding No. 7462

ANNUAL RESERVES AND MAXIMUM RATE LIMITATIONS FOR OIL POOLS

1. HEARING

A hearing was held by examiners appointed by the Board for the purpose of hearing representations respecting the crude oil reserves and maximum rate limitations of pools listed in the Notice of Hearing, issued December 21, 1973 and the Amended Notice of Hearing, issued January 15, 1974.

The hearing was conducted by N.A. Strom, P. Eng., G.H. Stafford, P. Geol., and H.J. Webber, P. Eng., on January 28, 29 and 30, 1974.

1.1 Appearances

The following were represented at the hearing:

	Represented by:	Abbreviation Used in Report
Amerada Minerals Corporation of Canada Ltd.	S.O. Asekun, P. Eng. S.B. Beveridge, P. Eng.	Amerada
Ashland Oil Canada Limited	D.H. Stright, P. Eng.	Ashland
Atlantic Richfield Canada, Ltd.	E. Chwyl, P. Eng. G.R. Turnquist	Atlantic
Chevron Standard Limited	L. Kolada, P. Eng.	Chevron
Hudson's Bay Oil and Gas Company Limited	B.J. McNeil, P. Eng. J. Juilfs, P. Geol.	Hudson's Bay
Imperial Oil Limited	J. Cochrane, P. Eng. B.T. Reilly, P. Eng. E.J. Muchowski	Imperial
Ipex Oil and Gas Ltd.	W.G. Fisher, P. Eng.	Ipex
Leddy Exploration Limited	H.F. Koetsier, P. Eng.	Leddy
Mobil Oil Canada, Ltd.	R.A. Slotboom, P. Eng. S.K. Bhatia, P. Eng.	Mobil

PanCanadian Petroleum Limited	L.S. Bowns, P. Eng.	PanCanadian
Skye Resources Ltd.	J.A. Irvine, P. Eng. R.W. Lamond	Skye
Energy Resources Conservation Board Staff	N.G. Berndtsson, P. Eng. G.R. Heming, P. Eng.	Board staff

2. REPORT CONTENT AND TERMINOLOGY

2.1 Content of Report

Section	
1.	Hearing
2.	Report Content and Terminology
3.	Pembina Keystone Belly River B Pool
4.	Pembina Keystone Belly River C Pool
5.	Pembina Keystone Belly River L Pool
6.	Pembina Keystone Belly River U Pool
7.	Edson Cardium C Pool
8.	Alderson Upper Mannville C Pool
9.	Medicine River Glauconitic A Pool
10.	Boundary Lake South Triassic E Pool
11.	Pouce Coupe South Boundary A Pool
12.	Alexis Banff A Pool
13.	St. Albert-Big Lake D-2A Pool
14.	Sturgeon Lake D-3 Pool
15.	Judy Creek Beaverhill Lake B Pool
16.	Rainbow Keg River GG Pool
17.	Utikuma Lake Keg River Sandstone A Pool
18.	Summary of Recommendations of Examiners
19.	Decision

2.2 Abbreviations, Terminology and Definitions

2.21 Reserves Terminology

The meanings of the terms used in this report are consistent with the meanings set out in the Board's report "Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur, Province of Alberta - ERCB 73-18."

2.22 Standard Conditions of Measurement

In this report, unless otherwise indicated, volumes of gas are at standard conditions of 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

2.23 Abbreviations

The abbreviations used in this report have the following meaning:

bbl	barrel
Bopd	barrels of oil per day
Bcf	billion cubic feet
GOR	gas-oil ratio
Kh	horizontal permeability
Kv	vertical permeability
MER	maximum efficient rate
MRL	maximum rate limitation
MMcf	million cubic feet
Mstb	thousands stock tank barrels
MMstb	million stock tank barrels
N	initial oil in place
PRL	preliminary rate limitation
psig	pounds per square inch gauge
psi	pounds per square inch
Ri	recovery factor
RiN	recoverable reserves

stb	stock tank barrel
WOR	water-oil ratio

2.24 K Factor

The term K factor is used in the report and has the meaning as defined in the PRL formula:

$$PRL = K \times 10^{-6} \quad (U - \tfrac{1}{2}P)$$

Where:

PRL = preliminary rate limitation, barrels of oil per month,
K = factor ranging from 7,000 to 11,000
U = recoverable crude oil reserves, stb
P = cumulative crude oil production, stb

2.25 Pool Names

For purposes of brevity, pool names are written out in full at the heading of each section and thereafter are abbreviated. For example, where "Pembina Keystone Belly River B Pool" is the full name, in the text it is simply the "B Pool."

2.27 Well Names

In this report the legal Subdivision, Section, Township and Range is used to denote a well location. For example, "the 4-22-47-3 well" or "the well in 4-22-47-3" denotes the well located in Legal Subdivision 4, Section 22, Township 47, Range 3. The meridian involved is obvious from the location of pools under consideration.

3. PEMBINA KEYSTONE BELLY RIVER B POOL

3.1 Reserves

3.11 Views of Ashland

Ashland's submission dealt only with the reserves for the portion of the pool comprising the Pembina Belly River B North Unit (Project No. 67). For this portion of the pool Ashland estimated that the rock volume of the oil zone is 74,828 acre feet. This does not include oil in Section 10, Township 48, Range 3, although Ashland considered it to be part of the B Pool.

Ashland contended that there was an original gas-oil contact at 330 feet subsea which is substantiated by drill stem tests and production history. The size of this gas cap is approximately one Bcf.

Ashland used new oil base core data obtained from the wells in

12-9-48-3 and 4-16-48-3, to estimate the initial water saturation of 0.42 for Project No. 67.

Referring to the reservoir simulation study of this portion of the pool submitted to the Board in September 1972, Ashland contended that water flood performance data supports the prediction that 0.402 of the oil in place would be recovered for the 80-acre 9-spot pattern.

3.12 Views of Examiners

The examiners have reviewed the drill stem test and production data and note that the only clear indication of a gas cap is in Section 10. The examiners believe that there is insufficient evidence to warrant changing the pool designation to place Section 10 the B Pool. On this premise the examiners conclude, in opposition to Ashland's view, that no primary gas cap existed in the B Pool.

The examiners recommend assigning the following factors for Project No. 67:

rock volume (acre feet)	79,000
porosity	0.195
water saturation	0.43
shrinkage factor	0.89

The examiners recommend that the presently assigned recovery factor of 0.35 be retained for Project No. 67 pending completion of more peripheral wells and obtaining additional performance data.

Based on the foregoing, the examiners recommend assigning the following reserve values for Project No. 67:

N (Mstb)	60,600
Ri	0.35
RiN (Mstb)	21,200

3.2 Maximum Rate Limitation

3.21 Views of Ashland

Ashland proposed that an MRL of 6,000 Bopd be assigned for the 80-acre 9-spot water flood in Project No. 67 in the B Pool. This MRL is based on the proposed recoverable reserves of 24,120 Mstb and a K factor of approximately 8,200.

The present MRL for the project, of 4,600 Bopd was determined using the PRL formula and a K factor of 7,000. Ashland stated that K factors of 9,000 and 8,750 for an 80-acre 5-spot and an 80-acre 9-spot respectively, are equivalent to a K factor of 7,000 for a 160-acre 9-spot based on velocity distribution calculations. So far, about half of the scheme has been converted from 160-acre to 80-acre 9-spot. Ashland pointed out that the rapid breakthrough of water to the 10-17-48-3 well was probably due to an overly large fracture treatment.

3.22 Views of Examiners

The examiners note that well productivities are highly variable and that some wells may have to be operated below actual capability to avoid excessive skewing of flood fronts. The examiners regard the recent indications of water breakthrough at a number of wells, in addition to the 10-17-48-3 well, as evidence that the reservoir is fairly stratified. Therefore, while the examiners recognize the general argument that flow velocity can be reduced by reducing the size of each flood pattern, they are of the opinion that a K factor of 7,000 is reasonable for the conditions that exist. The examiners recommend retaining a K factor of 7,000 for the present time.

4. PEMBINA KEYSTONE BELLY RIVER C POOL

4.1 Reserves

4.11 Views of Ashland

Ashland estimated a rock volume for the Board designated pool area to be 67,800 acre feet. Its estimate included the rock volume in Section 10, Township 48, Range 3, although it contended that there may be separation between Section 10 and the remainder of the C Pool. Ashland estimated the gas-oil contact in Section 10 at 330 feet subsea as compared to the estimated gas-oil contact of 310 feet subsea for the remainder of the pool.

Using the rock volume for the designated pool area, average porosity of 0.194, connate water saturation of 0.44 and shrinkage factor of 0.90, Ashland calculated the oil in place to be 51,445 Mstb. Ashland did not provide oil in place data for the current project area.

Ashland proposed assigning a recovery factor of 0.417, the same value as that proposed in its application for a water flood scheme in 1972, to be applicable when the water flood scheme is extended to the entire pool.

4.12 Views of Examiners

The examiners find that the additional evidence does not materially change the interpretation considered previously by the Board and recommend no change in the assigned reservoir factors for the C Pool. The examiners note that water injection commenced in December, 1973 and several months may elapse before the scheme is fully operational. The examiners therefore recommend retaining the existing reserves values of:

N (Mstb)	41,100
Ri	0.13
RiN (Mstb)	5,340

The examiners find no new evidence to change the recovery factor of 0.35 for water flood operations.

4.2 Maximum Rate Limitation

4.21 Views of Ashland

Based on the two-dimensional cross-sectional model and the velocity distribution studies discussed in the Pembina Keystone Belly River B Pool, Ashland requested that an MRL of 5,900 Bopd be assigned when the 80-acre 5-spot water flood scheme is extended to the whole pool.

4.22 Views of Examiners

The examiners recommend retaining, for the present time, a K factor of 7,000 for the determination of MRL's for the C Pool. Comparisons of resulting MRL values are shown on Table 18.3.

5. PEMBINA KEYSTONE BELLY RIVER L POOL

5.1 Reserves

5.11 Views of Ashland

Ashland estimated the total rock volume for the L Pool to be 43,843 acre feet. This included the rock volume in the south-east quarter of Section 15, Township 48, Range 3, an area designated by the Board as part of the Pembina Keystone Belly River B Pool. Ashland estimated the rock volume within the future water flood area to be 33,600 acre feet.

Ashland submitted that a gas cap of 80 MMcf exists in the L Pool with an original gas-oil contact at 273 feet subsea. Ashland contended that the existence of the gas cap was substantiated by production data.

On the basis of the new oil base core data obtained from the wells in 12-9-48-3 and 4-16-48-3, in the Pembina Keystone Belly River B Pool, Ashland estimated an average water saturation of 0.43 for the L Pool.

In answer to questions, Ashland stated that there was no new data to be considered since submittal of the application for the water flood scheme a year ago. Ashland stated that its studies in other pools had indicated that an infill drilling program to reduce the well spacing from 160 acres to 80 acres would result in an increase in the expected water flood recoverable reserves of about 0.05 of the oil in place. In anticipation of full development on 80-acre spacing, Ashland recommended assigning a recovery factor of 0.466 to the future water flood area.

5.12 Views of Examiners

The examiners note that the geological limits and reservoir factors for the L Pool were thoroughly considered pursuant to an application for a water flood scheme submitted a year ago. With the exception of the new water saturation data, the examiners note that there is no new evidence in the form of drilled wells, production performance, or other data which would lead to a revised interpretation of reservoir factors. The examiners therefore adopt the presently assigned rock volume of 40,000 acre feet for the pool, of which 33,000 acre feet will be assigned to the water flood project when it becomes operational.

The examiners agree with Ashland's interpretation that the average water saturation is 0.43. The examiners find no new evidence to alter the previously assigned recovery factors of 0.13 for primary depletion and 0.37 for the future water flood area.

The examiners recommend assigning the following reserve values for the L Pool:

N (Mstb)	30,900
R_1	0.13
R_1N (Mstb)	4,020

5.2 Maximum Rate Limitation

5.21 Views of Ashland

Based on the two-dimensional cross-sectional model and velocity distribution studies discussed in the Pembina Keystone Belly River B Pool submission, Ashland requested that on MRL of 3,400 Bopd be assigned for an 80-acre 5-spot water flood scheme when it is fully operating for the whole pool.

5.22 Views of Examiners

The examiners recommend retaining a K factor of 7,000 for the determination of MRL's for the L Pool.

6. PEMBINA KEYSTONE BELLY RIVER U POOL

6.1 Reserves

6.11 Views of Ashland

Ashland interpreted the total pool oil in place for the U Pool to be 55,810 Mstb. This interpretation was based on a revised water saturation of 0.44 and a rock volume incorporating recently drilled wells outside the southern pool boundaries.

Ashland did not submit a primary recovery factor estimate. However, for the water flood area it proposed applying a recovery factor of 0.40 for an 80-acre 5-spot pattern. It acknowledged that 80-acre development is still pending and that its calculated recovery factor for the existing 160-acre 9-spot was 0.34. Ashland submitted an oil in place value of 45,317 Mstb for the unit area to which it applied the recovery factor of 0.40 to determine recoverable reserves. Ashland agreed that part of the unit was classified as primary acreage and should not receive the assigned water flood recovery factor at this time. Ashland's interpretation of oil in place for the primary area of the unit is 7,670 Mstb. By difference the oil in place for the recognized project area is 37,700 Mstb.

When questioned as to why injectivity and productivity were substantially lower than predicted, Ashland indicated that the shortfalls were due to completion problems at the injection wells. Ashland also stated that no water breakthrough had occurred and, although the voidage replacement ratio during 1973 was less than unity, the cumulative project voidage replacement ratio to December 31, 1973, was greater than unity.

6.12 Views of Leddy

Leddy interpreted the oil in place in the portion of the U Pool which is outside of the unit to be 10,285 Mstb. Applying a recovery factor of 0.13, it estimated recoverable reserves to be 1,337 Mstb. Leddy's interpretation of rock volume included evidence from recently drilled wells outside of the pool boundaries. While its oil in place value is based on a water saturation of 0.50, it recommended adoption of the lower water saturation of 0.44 indicated by the recently obtained oil base core in the Pembina Keystone Belly River B Pool. This approach would result in an oil in place of 11,500 Mstb and primary recoverable reserves of 1,500 Mstb.

6.13 Views of Examiners

The examiners note that estimation of the zero isopach for the U Pool is subject to considerable interpretation and, in fact, cannot be reasonably defined at the southern end of the pool. Having regard for these uncertainties, the examiners consider it reasonable to establish rock volume on the basis of isopach values within validatable acreage. Also, because there are considerable variations in reservoir rock quality, the examiners consider it appropriate to establish oil in place and recoverable reserves by dividing the pool into those parts defined as the recognized enhanced recovery area and the primary area. The examiners agree to incorporating wells at the southern perimeter since these are unquestionably part of the pool.

The examiners note that, while water flood response has been positive in Project No. 20, productivity is only about half that predicted by Ashland. The examiners regard the lower productivity as potentially significant with respect to the realization of presently assigned water flood reserves if the completion problems at both injectors and producers are not rectified. The examiners therefore consider it appropriate to continue to apply the water flood recovery factor of 0.31 pending further observation of performance. The examiners also agree that a primary recovery factor of 0.13 is appropriate.

The examiners recommend the adoption of the following reserves factors:

	Primary Area	Project No. 20
N (Mstb)	19,600	34,800
Ri	0.13	0.31
RiN (Mstb)	2,550	10,800

6.2 Maximum Rate Limitation

6.21 Views of Ashland

Based on the two-dimensional cross-sectional model and the velocity distribution studies discussed in the Pembina Keystone Belly River B Pool submission, Ashland requested that an MRL of 5,000 Bopd be assigned for an 80-acre 5-spot water flood scheme in the unit area of the U Pool. This is based on recoverable reserves of 18,127 Mstb (using a recovery factor of 0.40) and a K factor of 9,000. Ashland agreed that a K factor of 7,000 would be appropriate for the 160-acre inverted 9-spot project area.

6.22 Views of Leddy

Leddy did not present any views concerning MRL's.

6.23 Views of Examiners

The examiners recommend retaining, for the present time, a K factor of 7,000 for determination of MRL's in the U Pool.

7. EDSON CARDIUM C POOL

7.1 Reserves

7.11 Views of Ipex

Ipex interpreted the C Pool to be a long thin sandstone bar approximately 1 mile wide and about 14 miles long. Ipex was of the opinion that the two wells at the southern extremity of the pool in Sections 30 and 31 of Township 52, Range 17, are separated from the remainder of the pool by a fault. The two wells in this area are structurally lower and yet produce at much higher gas-oil ratios than the other wells in the pool.

Ipex proposed a rock volume of 51,420 acre feet for the main portion of the pool from which an oil in place of 19,270 Mstb was calculated. In determining the initial recoverable reserves, Ipex employed a primary recovery factor of 0.12 based on values assigned to similar pools and having regard for the greater volatility of the oil in the subject pool.

7.12 Views of Examiners

While they agree for the most part with the geological interpretation presented by Ipex, the examiners believe that there is currently insufficient well control to extend the northern portion of the C Pool beyond Section 28 of Township 53, Range 18. The examiners recommend that a rock volume of 38,000 acre feet and oil in place of 13,500 Mstb, be established for the main portion of the pool.

Considering the structural position of the wells in Sections 30 and 31, Township 52, Range 17, and production performance data, the examiners agree with Ipex that a separate pool should be declared in this area and recommend that a rock volume of 10,000 acre feet resulting in an oil in place of 2,530 Mstb be established for this new pool.

In general, the examiners concur that the recovery efficiency is expected to be greater for pools having a more volatile oil. However, in the case of these pools there is insufficient information to substantiate an increase in recovery factor at this time. Therefore, the examiners recommend retaining a recovery factor of 0.10.

8. ALDERSON UPPER MANNVILLE C POOL

8.1 Reserves

8.11 Views of PanCanadian

The C Pool produces from a Glauconitic sand in an area where the sand is developed in a series of more or less parallel off-shore bars deposited on the crests of Mississippian highs. The oil accumulation is overlain by a small gas cap with a gas-oil contact at 745 feet subsea. PanCanadian proposed a rock volume of 2,830 acre feet from which an oil in place of 2,570 Mstb was calculated.

PanCanadian proposed a recovery factor of 0.10 based on that assigned to similar Mannville pools in the area. It contended that a recovery factor of 0.10 is reasonable having regard for the relatively low producing GOR's of the well in 4-4-16-15.

8.12 Views of Examiners

The examiners are in agreement with the basic geological description of the pool presented by PanCanadian. The examiners recommend a rock volume of 2,516 acre feet which results in an oil in place of 2,500 Mstb.

The examiners believe there is insufficient production history for the 4-4-16-15 well to indicate that it will continue to produce at lower GOR's than the other wells in the pool. Taking into consideration the performance of the other wells in the pool, the examiners recommend that a recovery factor of 0.05 be assigned.

9. MEDICINE RIBER GLAUCONITIC A POOL

9.1 Coalescence of the Medicine River Glauconitic E Pool and A Pool.

9.11 Views of Hudson's Bay

Hudson's Bay submitted that the Medicine River Glauconitic E Pool and the Medicine River Glauconitic A Pool have been considered as separate pools because of a difference in producing characteristics and because the single well in the E Pool was discovered with an initial pressure of 2,500 psig compared to the initial pressure of 3,700 psig in the A Pool.

9.12 Views of Examiners

The examiners note that a 1965 drill stem test on the well 11-22-38-4 in the E Pool recorded an initial shut-in pressure of 3,748 psig over the interval 4,065 to 4,130 feet subsea. This pressure is close to the initial pressure in the A Pool of 3,810 psig at 4,200 feet subsea recorded in 1963. The examiners also note that the sand in the E Pool is correlatable to the sands in the 4-27-38-4 and 12-27-38-4 wells in the A Pool. Accordingly, the examiners recommend that the subject pools be coalesced.

9.2 Reserves

9.21 Views of Hudson's Bay

On the basis of a net oil iso-porosity thickness map and the previously established values of connate water saturation of 0.25 and shrinkage factor of 0.66, Hudson's Bay calculated the oil in place to be 8,187 Mstb. Hudson's Bay applied the presently recognized recovery factors of 0.10 for primary and 0.20 for water flood to determine the recoverable reserves as shown in the table in Section 9.22.

9.22 Views of the Examiners

The examiners believe that the zero isopach of Hudson's Bay's net oil iso-porosity thickness map is somewhat optimistic on the eastern edge of the pool, as the wells in 2-9-38-4 and 10-20-39-4 are known to have tested gas. The examiners recommend assigning an oil in place of 75,800 Mstb for the pool. The examiners agree with the recommended recovery factors of 0.10 and 0.20 for primary and water flood areas respectively.

The recommended recoverable reserves for each area are as follows:

	Hudson's Bay		Examiners	
Project	N(Mstb)	RiN (Mstb)	N(Mstb)	RiN (Mstb)
Project No. 14	7,900	1,580	8,500	1,700
Project No. 15	13,208	2,642	13,100	2,620
Project No. 16	4,770	954	4,660	932
Project No. 18	11,069	2,214	9,500	1,900
Primary	46,240	4,624	40,000	4,000

10. BOUNDARY LAKE SOUTH TRIASSIC E POOL

10.1 Reserves

10.11 Views of Imperial

Imperial estimated the oil zone rock volume of the E Pool to be 96,165 acre feet. This value was backed out from the hydrocarbon pore volume determined from an iso-porosity-thickness isopach map and footage-weighted average porosity of 0.159. Individual well porosity thicknesses were determined for cored wells using cut-offs of 5 per cent for porosity and 1.0 millidarcy for permeability. Imperial stated that where core data was not available, values of porosity thickness were determined from sonic logs using a 59 microsecond cut-off. Applying the previously established average water saturation of 0.14 and shrinkage factor of 0.79, Imperial calculated the initial oil in place for the E Pool to be 81,250 Mstb. A gas-oil contact was interpreted at 1,900 feet subsea in the northern portion of the pool, resulting in an estimated gas cap pore volume of 10.06 million reservoir barrels.

In a previous study submitted to the Board in February 1972 Imperial reported a predicted recovery factor of 0.395 for the portion of the reservoir swept by water. Imperial stated that since the February 1972 reservoir study, several infill wells had been drilled to complete the established 7-spot injection patterns. The infill wells showed generally higher permeability thickness with about the same degree of stratification as the original wells. Therefore, a recovery factor of 0.40 was proposed for the portion of the reservoir that will be flooded by water. Imperial estimated that the portion of the pool which will be water flooded contained 63,670 Mstb of oil in place, of which 25,500 Mstb was estimated to be recoverable. This estimate included the wells 16-22-84-13 and 6-26-84-13 which have not yet been included in the water flood approval area. In addition to this, Imperial believed that 10 per cent of the remaining 17,580 Mstb of oil in place located in the edge areas of the pool, outside the floodable portion, would be drained by the project wells. Thus, Imperial estimated the total recoverable reserves to be 27,200 Mstb.

10.12 Views of Examiners

The examiners reviewed Imperials' interpretations and conclude that its net pay values for both cored and uncored wells are in the range of 10 to 15 per cent larger than the examiners would obtain using the same data. The examiners consider oil in place assigned to non-drilled edge tracts is poorly defined. In addition, the examiners note that the permeability of the reservoir rock is very low. Having these considerations in mind, the examiners recommend not assigning oil in place for non-drilled edge tracts. On this basis, the examiners recommend rock volumes for the portions of the pool subject to water flood and primary depletion be established at 65,000 and 3,000 acre feet respectively.

The examiners have considered the previously established recovery factor, the new data obtained by the drilling of the infill wells, and the performance of the existing scheme and agree with Imperial that a recovery factor of about 0.40 is appropriate for the area to be water flooded. However, the examiners do not accept Imperial's assumption concerning drainage of oil from fringe areas. Accordingly, the examiners recommend recoverable reserves for the water flood and primary areas of 21,900 Mstb and 253 Mstb respectively.

11. POUCE COUPE SOUTH BOUNDARY A POOL

11.1 Reserves

11.11 Views of Skye

Skye submitted that the oil in place of the A Pool as recognized by the Board should be increased from 9,140 Mstb to 33,000 Mstb, based on an increase in the rock volume confirmed by additional drilling in the southern portion of the pool.

Skye estimated a recovery factor of 0.11 for primary depletion using the Tracy method, and recoverable reserves of 3,630 Mstb for the pool.

11.12 Views of Examiners

The examiners accept that some increase in the established reserves of the pool is warranted as a result of the additional drilling, but believe that recognition of reserves in extensive undrilled areas in the southern and western portions of the pool as proposed by Skye is unjustified. The examiners understand that the well located in 6-22-77-11 would be a very marginal producer because it is in an area of low permeability. Therefore, assigning rock volume in the vicinity of that well is considered unrealistic in the determination of oil in place. The examiners believe that a more realistic estimate of the oil in place can be obtained by a "building block" approach including areas which could be validated using the Board's production spacing unit regulations. Using this method, an oil in place of 16,500 Mstb was calculated.

The examiners recommend that a recovery factor of 0.10 be established for the pool.

12. ALEXIS BANFF A POOL

12.1 Views of Ashland

Ashland submitted that it is currently reviewing a reservoir study to evaluate the feasibility of enhanced recovery and gas conservation in the subject pool, and requested that the reserves be established when this study is completed. Ashland said that the study will be submitted to the Board by March 31, 1974.

12.2 Views of the Examiners

The examiners note that the notice of hearing indicated that submissions respecting this pool were expected. In the absence of submissions, and having reviewed the pool's performance, with particular emphasis on the producing WOR and GOR, the examiners recommend revising the recovery factor downward to 0.05 from the present value of 0.15. Using this recovery factor and the currently recognized oil in place of 47,700 Mstb, the examiners estimate recoverable reserves to be 2,390 Mstb.

13. ST. ALBERT-BIG LAKE D-2 A POOL

13.1 Reserves

13.11 Views of Imperial

Imperial estimated the recoverable reserves of the D-2 A Pool to be 1,633 Mstb, using a volumetric oil in place of 2,477 Mstb and a recovery factor of 0.659. The recovery factor estimate was based on a terminal sandwich of 15 feet and a flushing efficiency of 0.683. In determining the flushing efficiency, Imperial placed the current oil-water interface at 2,238 feet subsea, as three wells completed over the interval 2,227 to 2,238 feet subsea have only recently started to produce water.

13.13 Views of Examiners

The examiners note that the oil in place submitted by Imperial agrees closely with the oil in place of 2,500 Mstb currently recognized by the Board. The examiners agree with Imperial that the presently assigned recovery factor of 0.42 is too low since recovery to the end of 1973 had already reached 0.39. The examiners have determined that an error of 1 foot in the estimated position of the oil-water interface would lead to an error of nearly 0.02 in the flushing efficiency. Having regard for the possible error in locating the oil-water interface, the examiners recommend assigning a recovery factor of 0.60.

13.2 Maximum Rate Limitation

13.21 Views of Imperial

Imperial applied for an MRL of 475 Bopd on the basis of the observed good performance at the current MRL level of 220 Bopd and the strong water drive in the pool. It also stated that the requested MRL was consistent with the indicated well capabilities determined on short duration tests, and would not adversely affect recovery. It indicated that it had not made any technical studies to determine rate sensitivities.

13.22 Views of Examiners

The examiners recommend basing the MRL on the revised recoverable reserves of 1,500 Mstb and a K factor of 11,000.

14. STURGEON LAKE D-3 POOL

14.1 Reserves

14.11 Views of Amerada

Amerada estimated the rock volume of this pool to be 244,920 acre feet based on maps submitted to the Board in reports in 1958 and 1965, and an average pool porosity of 0.0439 based on limited core and log data. On the basis of this information and the currently assigned water saturation and oil shrinkage factor, Amerada estimated the oil in place to be 44,100 Mstb.

Amerada stated that its three-dimensional model matched the pool WOR, GOR, oil production and pressure history with an input oil in place of 44,100 Mstb. The recovery factor was predicted to be 0.57 to 0.59 depending upon the assumed abandonment oil production rate and WOR. Based on the recovery factor of 0.58 from the model prediction, Amerada requested that recoverable reserves of 25,600 Mstb be adopted.

Amerada stated that its two-dimensional, three-phase coning model determined coning height relationships for high permeability, medium permeability and low permeability wells over a range of expected producing rates, and that these relationships were input into the three-dimensional model. Although a WOR history match of individual wells was not performed, Amerada said that the model correctly matched the historical WOR data on a pool basis.

Amerada stated that the limited core data on the subject pool indicated a Kv to Kh ratio of 1:10 to 1:100 and that extensive core data from the Sturgeon Lake South D-3 Pool indicated a Kv to Kh ratio of 1:50. It stated, however, that an average ratio of 1:100 was deemed most applicable for purposes of the three-dimensional simulator and the coning model. It stated that cone height is primarily a function of Kh while the time to reach stabilized cone height is mainly influenced by Kv. Amerada did not agree that assigning a Kv to Kh ratio of 1:100 in the model would virtually preclude coning. Amerada said that the model study indicated that water coning does not affect oil recovery from the pool over the range of production rates of 5,000 Bopd to 7,500 Bopd simulated by the model.

Subsequent to the hearing, Amerada submitted a geological interpretation of the location of the anhydrite in the pool which indicated that massive anhydrite occurs in Section 32 in intervals up to a maximum bed thickness of 11 feet and a maximum net thickness in any well of 12.5

feet. Anhydrite stringers about 1 foot thick are present at other wells in the immediate area. Amerada stated that the anhydrite lenses were not continuous through the pool and would not affect oil recovery.

Amerada said that it could not compare displacement efficiency calculations from the model with actual data of oil-water interface movement because the only observation well in the pool was completed above the current oil-water interface. However, it indicated that a new well had been approved as an observation well and was being deepened about 200 feet to give more definitive answers.

Amerada's submission showed that the predicted rise of oil-water interface to July 1, 1973, for each well varied from as little as 7 feet to as much as 45 feet. It said it believed that these variations actually existed and stated that recovery would be improved by leveling the interface.

Amerada estimated that a pressure maintenance scheme with full voidage replacement would recover about 1,000 Mstb of additional oil by preventing shrinkage losses from occurring.

14.12 Views of Examiners

Since no new oil in place data has been submitted for consideration, the examiners recommend that the currently established oil in place of 44,400 Mstb and the associated reservoir parameter values be retained for the pool.

The examiners question whether the model is sufficiently detailed to describe advance of the oil-water interface at various points in the pool. For example, the model indicates that the interface has risen only 7 feet at 1-32-71-23 compared to 34 feet at the off-setting 3-32-71-23 well. This variation is believed improbable. Since the coning correlations are based solely on theoretical calculations with no history matching to support them, the examiners regard them as only qualitative measures of coning tendencies.

The overall view of the examiners is that the model is inadequate for purposes of refining recovery estimates and gives only a qualitative indication of performance as functions of various withdrawal rates.

On the strength of the evidence presented, and recognizing that there is no field data from which to evaluate flushing efficiency, the examiners recommend retaining the currently assigned recovery factor of 0.50.

14.2 Maximum Rate Limitation

14.21 Views of Amerada

Amerada stated that its model prediction showed that water coning does not affect oil recovery from the pool over the range of pool production rates of 5,000 to 7,500 Bopd. On this basis and considering that the pool has produced at rates in excess of 7,000 Bopd, Amerada submitted that an MRL of 7,500 Bopd should be assigned to the pool.

14.22 Views of Examiners

The examiners hold the view that the model is inadequate for evaluating rate sensitivity. They note that the pool monthly WOR has increased over the last 2 years from zero to about 0.10, while in the same period the pool production rate increased from about 2,000 to 6,000 Bopd. The examiners consider this as evidence of rate sensitivity. They therefore recommend retaining a K factor at 11,000 and recommend assigning the resulting MRL of 6,000 Bopd for the pool.

15. JUDY CREEK BEAVERHILL LAKE B POOL

15.1 The Nature of the Reservoir and Oil In Place

15.11 Views of Imperial

Imperial stated that the B Pool is a carbonate reef of Middle Devonian age. The Swan Hills member of the Beaverhill Lake formation is divided into five stratigraphic zones designated S1, S2, S3, S4 and S5. The oil accumulation is confined to the three uppermost zones (S5, S4 and S3) with the oil-water interface occurring at 5,430 feet subsea. The lowermost zones (S2 and S1) are essentially impermeable.

Imperial stated that the pool outline was defined by a geological evaluation of the reef edge on the up-dip portion, and the intersection of the oil-water interface with the reef top and an interpretation of porosity pinch-out on the down-dip portion. Porosity thickness values for each well were based on core analysis data for cored sections and sonic log data for uncored sections. The individual well porosity thickness values were machine plotted and integrated to determine the pool total pore volume.

Imperial calculated the oil in place for the pool to be 265,700 Mstb, based on an oil zone rock volume of 733,618 acre feet and an average porosity of 0.0922 (equivalent to a total pore volume of 67,600 acre feet), and the currently assigned values of 0.17 for water saturation and 0.61 for shrinkage factor.

15.12 Views of Examiners

The examiners concur with Imperial's qualitative description of the reservoir. They also generally concur with Imperial's method of calculating the pool total pore volume. However, they question the mapping of pore volume peaks which are not based on well control and also believe that the areal extent of the reservoir in the south-west portion of the pool is optimistic.

The examiners recommend establishing oil in place of 260,000 Mstb, based on a rock volume of 719,000 acre feet, porosity of 0.092, water saturation of 0.17 and shrinkage of 0.61.

15.2 Recovery Factor

15.21 Views of Imperial

Imperial studied the performance of the Judy Creek Beaverhill Lake B Pool by means of a three-dimensional two-phase (oil and water) model defined by a 25 by 22 grid system, consisting of 80-acre cell blocks. The vertical direction was described using five layers: one for the S5 zone, three for the S4 zone and one for the S3 zone. The grid system was oriented so that the majority of the wells were located in diagonally adjacent grid blocks. There was no provision for vertical segregation of fluids within a layer.

The entire aquifer was included in the areal grid to simulate water influx effects. The grid also included the west flank of the Judy Creek Beaverhill Lake A Pool to simulate any inter-pool interference effects. Imperial stated that the model indicated that these two effects were of minor importance.

The model results indicated recoverable reserves of 145,000 Mstb equivalent to a recovery factor of 0.546.

Imperial submitted that field water flood performance indicated a recovery factor of 0.415 of oil in place in the flooded region (i.e. water breakthrough region) of the pool. Imperial contended that enough of the lagoonal area had been swept to account for its effect on the recovery factor calculation. Thus the recovery factor of 0.415 can be applied to the combined reefal and lagoonal areas. Also, Imperial determined from B Pool core flood tests that the ratio of recovery at 1 pore volume of water injected (equivalent to the terminal point of a field flood) to recovery at breakthrough is an average of 1.28. By applying this ratio to the field breakthrough recovery factor of 0.415, it estimated a final recovery factor of 0.531.

Imperial considered the model to be adequate for determining the reservoir's performance because a good pressure match was obtained. However, in order to obtain a good pressure match, the horizontal permeability in the grid blocks representing the reef framework were increased by a factor of 1,000. Imperial stated that the adjustment would only have been necessary in the parts of the reef framework initially assigned lower permeabilities. Imperial stated that the large adjustment to the reef framework permeability was also necessary to obtain a better match with the field observed flood front movement.

A residual oil saturation of 0.25 was used for the B Pool. This value was adopted having regard for an in situ tracer test and pressure cores obtained from swept regions of the Judy Creek Beaverhill Lake A Pool. Imperial made history match calculations using both the previously assigned value for residual oil of 0.36 and the currently assigned value of 0.25, and compared the results with field observed flood front positions at June 1973. The difference between the two cases was insufficient to conclude which residual oil saturation was more representative.

15.22 Views of Examiners

The examiners note that the reef framework is now emerging as a major component in assessing field performance. The examiners question whether Imperial's 1,000-fold increase in horizontal permeability for reef framework blocks is proper. They suggest, for instance, that a better approach might have been to subdivide the S5 zone into more than one horizontal layer. This might have yielded zones of significantly higher permeabilities from core analyses with little or no further adjustment necessary to achieve the pressure history match. It also may have provided for a more definitive match of flood front advance. Further in this regard, the examiners question whether the model is sufficiently refined to evaluate variations of performance and recovery with different rates of depletion. The examiners regard the water saturation maps presented by Imperial as only a nominal match with the interpretation of the field observed flood front movements.

The examiners consider the recovery factor estimate of 0.415 submitted by Imperial to be only roughly indicative of the final recovery factor for the pool. While the examiners reject application of a conversion factor of 1.28 obtained from core flood tests to field performance breakthrough data, they recognize that additional oil will probably be displaced from lower quality portions of the reservoir after breakthrough occurs.

Having regard for all of the evidence provided, the examiners conclude that there is insufficient basis to confirm that the final recovery factor for the B Pool will exceed the presently assigned value of 0.48. They recommend retaining a recovery factor of 0.48 and assigning a recoverable reserve of 125,000 Mstb.

16. RAINBOW KEG RIVER GG POOL

16.1 Reserves

16.11 Views of Chevron

On the basis of seismic and well bore information, Chevron estimated the oil in place of the GG Pool to be 8,650 Mstb. Chevron submitted that, in the absence of water injection, the aquifer and other expansion effects would be such as to result in a pool abandonment pressure of 1,461 psig or approximately 70 psi above the bubble point pressure. In determining this pressure, Chevron used an effective aquifer compressibility of 8.77 x 10^{-6} volume/volume/psi, an aquifer volume of 1,705 million reservoir barrels and recoverable oil of 12.796 million reservoir barrels for the pools on the aquifer system. Chevron calculated a recovery factor of 0.61 assuming residual oil saturation of 0.30 and a

30 foot sandwich loss at the crest of the pool. On this basis Chevron proposed that the recoverable reserves of the subject pool be increased from 3,680 to 5,280 Mstb.

16.12 Views of Mobil

Mobil estimated that, in the absence of water injection, the abandonment pressure in the GG Pool would be approximately 850 psig or approximately 540 psi below the bubble point pressure. Mobil requested that Chevron be required to arrange for replacement of withdrawals from the GG Pool and that the pool's pressure be maintained above 2,000 psig. In the event that the Board did not require Chevron to inject water, it was requested that Mobil be released of any responsibility to inject water on behalf of the GG Pool. In calculating the abandonment pressure in the absence of water injection into the Rainbow Keg River KK Pool, Mobil used an effective aquifer compressibility of 6.8×10^{-6} volume/volume/psi, an aquifer volume of 1,705 million reservoir barrels and recoverable oil for pools connected to the common aquifer system of 17.938 million reservoir barrels. Mobil concluded that, in the absence of water injection into the KK Pool, the recovery from the pools would be approximately 10 to 12 per cent lower than with pressure maintenance.

16.13 Views of the Examiners

The examiners note that the volumetric information presented by Chevron is basically the same information as was considered at the oil reserves hearing in 1969, and on this basis believe that no change in the recognized oil in place is warranted at this time.

Concerning the pressure drop in the absence of water injection into the KK Pool, the examiners note that the differences between the Mobil and Chevron interpretations stem from different effective rock compressibilities and different recoverable oil volumes estimated within the system. Based on the evidence presented at the hearing and similar evaluation made by the Board staff, the examiners conclude that the pressure of the GG Pool at the time of abandonment would be about 1,300 psig assuming no water injection into the aquifer system. Since the pressure of the GG Pool at the time of abandonment would be only about 100 psi below its bubble point, the examiners would not expect a secondary gas cap to form and also believe that very little adverse shrinkage and viscosity effects would occur.

Consistent with the Board's 1969 findings, the examiners believe that the presence of a saddle between the 12-9-109-5 well and the remainder of the pool will lead to some attic losses in the southern lobe of the pool. Taking into consideration these attic losses, a sandwich loss of 20 feet in the north lobe, and a residual oil saturation throughout the water-swept portion of the pool of 0.36, the examiners estimate a recovery factor of 0.47, and recoverable reserves of 3,840 Mstb.

The examiners agree that Mobil could apply to remove the GG Pool from those pools listed in its water injection scheme and thereby be released of the responsibility to inject water on behalf of the GG Pool. The examiners recommend that the matter of the need for maintaining the pressure of the GG Pool at 2,000 psig, as cited by Mobil, be pursued through an appropriate application to the Board.

17. UTIKUMA LAKE KEG RIVER SANDSTONE A POOL

17.1 Pool Designation

17.11 Views of Atlantic

The A Pool was interpreted by Atlantic from geological evidence from drilled.wells, seismic and dipmeter data to be comprised of three sand units: an upper sand unit of small areal extent, a middle or main sand unit of large areal extent and a lower sand unit of small areal extent. Atlantic stated that separation between the main sand unit and the overlying upper sand unit is quite clearly defined by different oil-water interfaces although the two units probably coalesce to the south and west of the field. According to Atlantic, the separation between the main sand unit and the lower sand unit is clearly defined throughout most of the area by a 30- to 50-foot shale interval and supported by pressure evidence. Structure and isopachs maps of net porous sand were constructed for each of the three sand units to determine productive limits.

Although Atlantic mapped three sand units and several accumulations within each sand unit, designation of separate pools was not recommended.

17.12 Views of Examiners

The examiners concur for the most part with Atlantic's geological interpretation of the A Pool. The concept of three separate sand units and separate accumulations within each unit is plausible. However, as communication could exist between the sand units as well as between accumulations laterally within each unit, the examiners recommend that a single pool designation be retained.

17.2 Oil in Place

17.21 Views of Atlantic

Atlantic estimated the oil in place for the A Pool to be 114,300 Mstb based on a rock volume of 128,453 acre feet determined from its isopach maps and other previously established reservoir parameters. When questioned about the accuracy of the seismic data which was used to develop the isopach maps, Atlantic indicated that prominent features could be readily identified but that interpretation of the details of the features was poor. Atlantic stated that approximately three-quarters of the oil indicated on the net pay isopach maps could be considered as proved reserves.

In order to substantiate its volumetric estimate, Atlantic performed simultaneous oil in place-water influx calculations using a straight line material balance approach for the combined Utikuma and Nipisi Keg River Sandstone system. The estimated oil in place for the A Pool derived by this method was 92,400 Mstb. Atlantic stated that it believed the material balance results were accurate to within 10 per cent of the actual value.

17.22 Views of Examiners

The examiners believe that there is considerable room for error in those parts of Atlantic's isopach maps based solely on seismic data. On the basis of Atlantic's estimated drainage area of 320 acres per well, the examiners calculated a rock volume of 82,000 acre feet from Atlantic's isopach maps. This is somewhat larger than the value of 70,000 acre feet that would be determined using the "building block" approach.

The examiners are concerned that the material balance approach for determination of oil in place is not sufficiently sensitive to be of much benefit in pools having a strong water drive. For example, Board staff calculations indicate oil in place ranging from 50,000 Mstb to 180,000 Mstb. The examiners recommend a rock volume of 80,000 acre feet and oil in place of 71,200 Mstb.

17.3 Recovery Factor

17.31 Views of Atlantic

Atlantic stated that the pool was being essentially pressure maintained as revealed as by the water drive index of 0.93. The nature of water encroachment, i.e. vertical or edge, was said to vary within the pool and be dependent upon local geological conditions.

Atlantic used structure maps to determine attic oil losses, and assumed a 5-foot terminal water cone height, a residual oil saturation of 0.31 and a conformance factor of 0.90 from which it estimated a recovery factor of 0.428 and recoverable reserves of 39,500 Mstb.

Atlantic indicated that, while its estimates were based on an assumed vertical water encroachment, it believed the recovery factor for the pool, if subject to edge water encroachment, would compare favorably to the water flood recovery factors recognized for the Nipisi and Mitsue Gilwood pools. (The water flood recovery factors for these pools are 0.43 and 0.47).

17.32 Views of Examiners

Calculations performed by the Board staff indicate that a recovery factor of about 0.40 would be obtained under a full bottom water encroachment process. Similar calculations assuming a full lateral water encroachment process for the pool result in a recovery factor of about 0.30. Having regard for the favorable performance shown and the probability of substantial bottom water encroachment, but with due regard for the complex pool geometry, the examiners recommend that a recovery factor of 0.35 be adopted.

18. SUMMARY OF RECOMMENDATIONS OF EXAMINERS

The examiners recommend that the reserves and reserve factors set out in Table 18.1 and the maximum rate limitations listed in Table 18.3 be adopted. For convenience, a comparison of previous, requested, and recommended reserves values is presented in Table 18.2.

19. DECISION

The Board agrees with the recommendation of the examiners and has adopted the reserves and reserve factors listed in Table 18.1 and the maximum rate limitations listed in Table 18.3.

ENERGY RESOURCES CONSERVATION BOARD

D R Craig

D.R. Craig,
Vice Chairman

Dated at Calgary, Alberta
March 20, 1974

TABLE NO. 18.1

EXAMINERS RECOMMENDED RESERVE FACTORS - POOLS AT JANUARY 28, 1974 RESERVES HEARING

FORMATION Pool	(1) AREA (Acres)	(2) PAY THICKNESS (Feet)	(3) POROSITY (Fraction)	(4) 1-WATER SATURATION (Fraction)	(5) OIL SHRINKAGE (stb/bbl)	( ) INITIAL OIL IN PLACE (Mstb)	( ) POOL RECOVERY PRIMARY (Fraction)	POOL RECOVERY ENHANCED (Fraction)	(8) RECOVERABLE OIL PRIMARY (Mstb)	RECOVERABLE OIL ENHANCED (Mstb)	RECOVERABLE OIL TOTAL (Mstb)
BELLY RIVER											
Pembina Keystone Belly River B	14,040					172,000			22,300	36,400	58,700
Project No. 67	4,000	(19.8)	0.195	0.57	0.89	60,600	0.13	0.22	7,880	13,300	21,200
Project No. 79	3,040	(27.0	0.194	0.47	0.88	51,100	0.13	0.22	6,640	11,300	17,900
Project No. 80	1,280	(10.9)	0.194	0.47	0.88	8,700	0.13	0.22	1,130	1,910	3,040
Project No. 81	4,160	(17.5)	0.194	0.47	0.88	45,200	0.13	0.22	5,880	9,940	15,800
MR'01	160	(16.4)	0.194	0.47	0.88	1,640	0.13	-	213	-	213
Primary	1,400	(5.0)	0.194	0.47	0.88	4,360	0.13	-	56[illegible]		567
Pembina Keystone Belly River C	[illegible]	(14.0)	0.191	0.55	0.89	41,100	0.13		5,3[illegible]0	-	[illegible],340
Pembina Keystone Belly River L	2,66[illegible]	(15.	0.1[illegible]6	0.57	0.89	30,900	0.13	-	4,020	-	[illegible],0[illegible]
Pembina Keystone Belly River U	5,4[illegible]0					54,400			7,070	6,260	13,400
Project No. 20	3,040	(15.0)	0.[illegible]94	0.57	0.89	34,800	0.13	0.18	4,520	6,260	10,800
Primary	2,400	(12.4)	.183	0.52	0.89	19,600	0.13	-	2,550	-	2,55[illegible]
CARDIUM											
Edson Cardium C	4,930	(7.7)	0.087	0.85	0.62	13,500	0.10	-	1,350	-	1,35[illegible]
South Portion (Edson Cardium D)	1,263	(7.9)	0.062	0.85	0.62	2,530	0.10	-	253	-	253
MANNVILLE											
Alderson Upper Mannville C	629	(4.0)	0.194	0.75	0.88	2,500	0.05	-	125	-	125
Medicine River Glauconitic A	12,883					75,800			7,580	3,580	11,2[illegible]
Project No. 14	1,1[illegible]5	(15.0)	0.130	0.75	0.66	8,500	0.10	0.10	850	850	1,[illegible]
Project No. 15	1,738	(15.1	0.1[illegible]0	0.75	0.66	13,100	0.10	0.10	1,310	1,310	2,[illegible]
Project No. 17	639	(14.6)	0.130	0.75	0.[illegible]6	4,660	0.[illegible]0	0.1	466	4[illegible]	[illegible]
Project No. 18	1,359	(14.0	0.130	0.75	0.66	9,500	0.10	0.10	950	95[illegible]	[illegible],900
Primary	8,0[illegible]2	(10.0	0.[illegible]30	0.75	0.66	40,000	0.10	-	4,000	-	4,000
TRIASSIC											
Boundary Lake South Triassic E	7,820					57,300			5,730	16,400	22,[illegible]
Water Flood	7,500	(8.[illegible])	0.160	0.86	0.79	54,800	0.10	0.30	5,480	16,400	21,[illegible]
Primary	320	(9.4)	0.160	0.86	0.[illegible]9	2,530	0.10		253	-	2[illegible]
Pouce Coupe South Boundary A	2,9[illegible]8	(7.9)	0.1[illegible]8	0.86	0.7[illegible]	16,500	0.10	-	1,650	-	1,[illegible]
BANFF											
Alexis Banff A	1,801	(46.1)	0.130	0.64	0.89	47,700	0.05	-	2,390	-	2,390
NISKU D-2											
S[illegible] Lake D-2A	300	(53.9)	0.029	0.78	0.88	2,500	0.60	-	1,500	-	1,500
LEDUC D-3											
Sturgeon Lake D-3	3,266	(61.0)	0.05[illegible]	0.85	0.6[illegible]	44,40[illegible]	0.50	-	22,200	-	[illegible]2,200
BEAVERHILL LAKE											
Judy Creek Beaverhill Lake B	1,225	(64.1)	0.092	0.83	0.6[illegible]	260,000	0.20	0.28	52,000	72,800	125,000
KEG RIVER											
Rainbow Keg River GG	471	(95.6)	0.[illegible]40	0.78	0.75	8,170	0.47		3,840	-	3,840
Utikuma Lake Keg River Sandstone A	8,893	(9.0)	0.190	0.71	0.85	71,200	0.35	-	24,900	-	24,9[illegible]

TABLE 14.

COMPARISON OF OIL IN PLACE AND RECOVERABLE RESERVES

(Thousands of Stock Tank Barrels)

Pool	Previous N	Previous RIN	Requested N	Requested RIN	Recommended N	Recommended RIN
Pembina Keystone Belly River B						
Project No. 67	61,000	21,400	60,000	24,120	60,600	21,200
Project No. 79	51,100	17,900	-	-	51,100	17,900
Project No. 80	8,700	3,040	-	-	8,700	3,040
Project No. 81	45,200	15,800	-	-	45,200	15,800
[illegible]	1,640	213	-	-	1,640	213
Primary	4,360	567	-	-	4,360	567
Pembina Keystone Belly River C						
Primary	9,400	1,220	N/A	N/A	9,400	1,220
Water Flood	31,700	4,120 (prim.)	51,445	21,453	31,700	4,120 (prim.)
Pembina Keystone Belly River L						
Primary	4,330	563	7,990	1,040	5,400	702
Water Flood	20,400	[illegible],650 (prim.)	26,210	12,220	25,500	3,320 (prim.)
Pembina Keystone Belly River [illegible]						
Project No. 20	39,600	2,230	37,700	15,100	34,800	10,800
Primary	15,740	2,050	17,900	2,330	19,600	2,550
Edson Cardium C	18,000	1,800	19,270	2,312	13,500	1,350
South Portion (New D Pool)	(included in above)		(not submitted)		2,530	253
Alderson Upper Mannville C	688	69	2,570	257	2,500	125
Medicine River Glauconitic A						
Project No. 14	9,050	1,810	7,900	1,580	8,500	1,700
Project No. 15	13,100	2,620	13,208	2,642	13,100	2,620
Project No. 16	4,660	932	4,770	954	4,660	932
Project No. 18	14,100	2,820	11,069	2,214	9,550	1,900
Primary	30,100	3,010	46,240	4,624	40,000	4,000
Boundary Lake South Triassic E						
Water Flood	56,000	22,400	81,250	27,230	54,800	21,900
Primary	30,100	3,010	(included in above)		2,530	253
Pouce Coupe South Boundary A	9,140	1,370	33,000	3,630	16,500	1,650
Alexis Banff A	47,700	7,160	(none submitted)		47,700	2,390
St. Albert-Big Lake D-2A	2,500	1,050	2,477	1,633	2,500	1,500
Sturgeon Lake D-3	44,400	22,200	44,100	25,600	44,400	22,200
Judy Creek Beaverhill Lake B	256,000	12[illegible],900	265,000	145,000	260,000	125,000
Rainbow Keg River G	8,170	3,680	8,650	5,280	8,170	3,840
Utikuma Lake Keg River Sandstone A	62,300	13,700	92,400	39,500	71,200	24,900

TABLE 15.3

COMPARISON OF MAXIMUM RATE LIMITATIONS

Pool	Previous[1] K Factor (x 10^3)	Previous[1] MRL (Bopd)	Requested K Factor (x 10^3)	Requested MRL (Bopd)	Recommende K Factor (x 10^3)	M (Bo
Pembina Keystone Belly River B Project No. 67	7	4,600	8.2	6,000	7	4,
Pembina Keystone Belly River C						
Whole pool water flood	-	-	9	5,900	7	3,
Whole pool primary	7	1,100	-	-	7	
Project No. 1 Water flood status area	-	-	-	-	7	2,
Pembina Keystone Belly River L						
Whole pool water flood	-	-	9	3,400	7	2,
Whole pool primary	7	620	-	-	7	
Pembina Keystone Belly River U						
Project No. 20	7	2,700	7	3,300	7	2,
Primary	7	890	-	-	7	
St. Albert-Big Lake D-2A	11	220	-	475	11	
Sturgeon Lake D-3	11	6,300	-	7,500	11	6,

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[1] Based on production to December 31, 1972

[2] Based on production to December 31, 1973

ENERGY RESOURCES CONSERVATION BOARD

Decision 74 - 4
Application No. 7372

PROCESSING PLANT ON PLAINS DIVISION OF THE ALBERTA GAS TRUNK LINE COMPANY LIMITED SYSTEM

1.0 THE APPLICATION AND HEARING

Consolidated Natural Gas Limited applied pursuant to section 38 of The Oil and Gas Conservation Act for approval of a scheme for the construction and operation of a gas processing plant to be located in the North-east quarter of Section 2, Township 20, Range 1, West of the 4th Meridian. Initially, the plant would be of the adsorption type, designed to process 350 million cubic feet per day of marketable pipe line gas for the recovery of 346 million cubic feet of residue gas and 2,059 barrels of a propane plus mix. Ultimately, the plant would be of the turbo expander type, processing 350 million cubic feet of raw gas daily for the recovery of 341 million cubic feet of residue gas and 3,900 barrels of a propane plus mix.

Notice of the application was published by the Board on November 15, 1973. A number of objections were filed. As a result of these objections, the application was heard by the Board in Calgary, Alberta on February 5 and February 6, 1974 with G. W. Govier, P. Eng., D. R. Craig, P. Eng. and V. Millard sitting.

2.0 APPEARANCES

Interventions to the application were received from The Alberta Gas Trunk Line Company Limited, Dome Petroleum Limited, Pacific Petroleums Ltd., PanCanadian Gas Products Ltd., and TransCanada PipeLines Limited. Amoco Canada Petroleum Company Ltd. and Pan-Alberta Gas Ltd. intervened for the purpose of cross-examination and argument.

The following appeared at the hearing:

	Represented by
Consolidated Natural Gas Limited (Consolidated)*	G.D. Nichols
The Alberta Gas Trunk Line Company Limited (Trunk Line)*	G.R. Forsyth, Q.C.
Amoco Canada Petroleum Company Ltd. (Amoco)*	J.D. Foster
Dome Petroleum Limited (Dome)*	C.E. Crawford
Pacific Petroleums Ltd. (Pacific)*	G.W. Lade
Pan-Alberta Gas Ltd. (Pan-Alberta)*	R.C. Muir
PanCanadian Gas Products Ltd. (PanCanadian)*	C. Millar
TransCanada PipeLines Limited (TransCanada)*	L.H. Pilon
Energy Resources Conservation Board (Board)*	N.A. Macleod, Q.C. G.J. DeSorcy, P.Eng R.J. Reimond, C.E.T.

3.0 BACKGROUND

TransCanada and Consolidated currently purchase gas at various field points throughout Alberta and remove the gas from the Province, under authorizing permits from the Energy Resources Conservation Board, at a border point near Empress, Alberta. The gas is delivered to the border through facilities of Alberta Gas Trunk Line. Trunk Line has two main gathering systems in the Province. One is the Foothills Division. The other is the Plains Division which delivers gas to Empress for removal from the Province. Both TransCanada and Consolidated buy volumes of gas which are delivered to each of the Foothills and Plains Divisions of Trunk Line. Since they take delivery of gas from the Plains Division, this necessitates an exchange of gas between the Foothills and Plains Divisions. Additionally, the TransCanada, Consolidated and other gas is commingled in the Plains Division of Trunk Line. Due to the exchange between the Foothills and Plains Divisions and the commingling of gas, Consolidated does not receive from Trunk Line the same gas which it tenders to the system.

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*Abbreviations in brackets are used throughout report.

Consolidated does not have a licence to export its gas from Canada to its market area and consequently sells its gas to TransCanada for shipment to eastern Canada to be marketed by TransCanada. The TransCanada gas, including that which it purchases from Consolidated, is processed for liquid hydrocarbon recovery before it is removed from Alberta. The processing takes place in two separate processing plants located at Empress, one operated by Pacific and the other by Dome. The information available to the Board indicates that by a contract dated June 1, 1962, Pacific and TransCanada agreed that Pacific would process, for the recovery of natural gas liquids, 1.5 billion cubic feet per day of gas owned by TransCanada. In 1969, an agreement was reached between Dome and TransCanada by which Dome would process 1.5 billion cubic feet per day of gas owned by TransCanada in a second plant at Empress. A further contract between Pacific, PanCanadian and TransCanada was made on October 29, 1971, by which Pacific and PanCanadian were given rights to process an additional 0.5 billion cubic feet per day of TransCanada gas. The gas which Consolidated would process in the facilities applied for is thus currently being processed in existing facilities.

4.0 STATUTORY PROVISIONS

4.1 Provisions Under Which the Application was Made

The Consolidated application was made under section 38 of The Oil and Gas Conservation Act, of which the parts applying to gas processing are as follows:

> 38. (1) No scheme for
>
> (b) the processing or underground storage of gas

shall be proceeded with unless the Board, by order, has approved the scheme upon such terms and conditions as the Board may prescribe.

(2) Prior to the Board approving a scheme under subsection (1), clause (b) or (d), it shall refer the application to the Minister of the Environment for his approval with respect to the application as it affects matters of the environment.

(3) The Minister of the Environment may give his approval with or without conditions, but where conditions are imposed, the Board shall, if it approves the scheme, make its order subject to the same conditions imposed by the Minister of the Environment when he gave his approval.

(4) Notwithstanding subsection (3), the Board is not required to impose the conditions specified by the Minister of the Environment when the Lieutenant Governor in Council directs that the conditions are not to be imposed.

4.2 Common Processor

At the hearing, references were made to the common processor provisions of The Oil and Gas Conservation Act. They read as follows:

54. (1) Upon application and after a hearing, the Board, with the approval of the Lieutenant Governor in Council, may declare any person who is the owner or operator of a processing plant processing gas produced from a pool or pools in Alberta to be a common processor of gas from the pool or pools.

(2) Subsection (1) does not apply to a person declared to be a common purchaser under section 52 or where an operator had entered into a contract approved under section 11 of The Gas Utilities Act.

(3) Each common processor shall process gas which may be made available for processing in his plant without discrimination in favour of one producer or owner of gas as against another in the pool or pools.

(4) No common processor shall discriminate in favour of his own gas or gas in which he is directly or indirectly interested either in whole or in part.

55. The Board, by order, may relieve any common processor, after due notice and hearing, from the duty of processing any gas of inferior or different quality or composition or from such other duties as in its opinion are unreasonable.

4.3 The Alberta Gas Trunk Line Company Act

Many of the arguments heard arose from the fact that the gas that would be delivered by Trunk Line to the proposed Consolidated processing plant would not be the same gas that had been received by Trunk Line from Consolidated. The authority for such operations of Trunk Line are to be found in The Alberta Gas Trunk Line Company Act. The relevant sections are as follows:

2. In this Act, unless the context otherwise requires,

(a1) "commingle", with reference to gas, means the mixing together or blending of gases received by the company from various points on its system for transmission through its pipe lines and other facilities;

(b1) "exchange", with reference to gas, means the exchange of gas received by the company into its gas pipe line system for delivery to a point in the company's system to which physical transmission of such gas is not practical, for other gas in the company's system which can practically be delivered to that point;

13. (2) In the exercise of its powers the company has the right to commingle gas or to exchange gas in its pipe lines or other facilities or any part or parts thereof irrespective of the ownership of the gases commingled or exchanged.

30b. (1) The company shall from time to time define or prescribe terms and conditions of service applicable to its pipe lines and other facilities or any part or parts thereof.

(2) Before accepting gas into its pipe lines or other facilities the company may require the gas to be processed or otherwise treated to a standard or quality specification determined by the company.

(3) Where gas owned by a person is commingled with or exchanged for gas owned by another person within a pipe line or other facility of the company, the company when delivering the commingled or exchanged gas is authorized to make whatever compensating adjustments in volume, heating value and component content as in its opinion are warranted.

(3.1) Prior to the implementation of an exchange of gas, the company shall mail by prepaid registered mail to the owners of the gas which would be the subject of such exchange, a notice of intention to exchange gas and shall file on the date of the mailing a copy of the notice with the Energy Resources Conservation Board.

(4) Upon application for service or for any variation in service through or by any pipe line or other facility of the company, the company may vary or adjust to the extent it deems necessary any existing contract or arrangement with any person in respect of that pipe line or facility.

30c. (1) Upon complaint in writing of an interested party respecting a decision made by the company under section 30b, the Energy Resources Conservation Board under The Energy Resources Conservation Act, may, after notice to and hearing of the parties interested, determine the reasonableness of the decision made by the company and by order in writing may vary or confirm the decision.

(1.1) Where a complaint arises out of a proposed exchange of gas, the complaint must be received by the Energy Resources Conservation Board within 90 days after the date of mailing of the notice of intention to exchange gas and if no complaint is received by the Energy Resources Conservation Board within that time the company may implement the proposed exchange.

(3) In the event of conflict between any term or condition of an order made under subsection (1) with any provision of an existing contract or arrangement, the term or condition of the order shall prevail.

5.0 SPECIAL PROBLEMS RAISED IN INTERVENTIONS BUT NOT PART OF AN APPLICATION UNDER SECTION 38 OF THE OIL AND GAS CONSERVATION ACT

Several of the interveners drew the Board's attention to the fact that Consolidated would not be receiving and processing the same gas which it tendered to Trunk Line. They raised questions concerning the matter of an appropriate compensating adjustment for the different gas composition. Other interveners questioned whether Consolidated had the legal right to process the gas as proposed in the application.

Regarding the compensating adjustment question, the Board stated at the opening of the hearing that The Alberta Gas Trunk Line Company Act provides for resolution of this matter in that it empowers Trunk Line to commingle gas and, when delivering the commingled gas, to make whatever compensating adjustments in volume, heating value and component content as in its opinion are warranted. The Act further provides that upon complaint in writing of an interested party respecting a decision made by Trunk Line regarding compensating adjustments, the Energy Resources Conservation Board may, after notice to and hearing of the parties interested, determine the reasonableness of the decision made by Trunk Line and by order in writing vary or confirm the decision. The Board gave an opinion that the consideration of an application under section 38 of The Oil and Gas Conservation Act for the approval of gas processing facilities, such as is put forward by Consolidated, need not be delayed pending resolution of the commingling or exchange problem. The Board stated that if it were to approve the construction and operation of the processing facilities applied for prior to resolution of the commingling problem the applicant would be free to commence the construction related to its facilities. It would be doing so, however, fully aware that it is subject to any later adjustment considered warranted by Trunk Line, subject to the appeal provisions in The Alberta Gas Trunk Line Company Act. For the above mentioned reasons, the Board indicated that it would not consider evidence at the subject hearing respecting the compensating adjustment problem. The Board reaffirms that position and will not, in this decision, deal with the compensating adjustment matter as an issue relevant to the disposition of the subject application.

Regarding the question of the legal right of Consolidated to process the gas in question, the Board stated at the hearing that it is not the proper tribunal to rule on the question of ownership. Such matters should be settled in the courts. The Board indicated that it would be prepared to dismiss, for ownership reasons, a processing application made under section 38 of The Oil and Gas Conservation Act, only in the event that the evidence clearly established that the applicant did not have ownership rights to the gas it intends to process. The Board stated that this did not appear to be the case in the subject application. The Board thus ruled that it would not consider evidence related to the legal right of Consolidated to process the gas in question. Accordingly, such matter will not be dealt with in this decision.

Dome submitted that the application "cannot be effectively dealt with by the Board or the Interveners herein before Trunk Line had advised what compensating adjustments in volume, heating value and component content are warranted in its opinion in delivering custody of gas to Consolidated's proposed plant, pursuant to Section 30b of the Alberta Gas Trunk Line Company Act". Dome thus requested "that the hearing be postponed until such advice is obtained from Trunk Line and made available to the Board and interested parties". Pacific supported the request of Dome. The Board, for the reasons outlined earlier respecting the question of compensating adjustments, ruled against the postponement and the hearing proceeded. The Board notes that Trunk Line stated at the hearing that its intended approach to making the adjustments provided for by The Alberta Gas Trunk Line Company Act is outlined in its submission to the Board respecting the subject application.

6.0 DEFINITION OF ISSUES

The Board considers that the following issues are relevant to the disposition of the subject application.

(a) Conservation Considerations

These include conservation in the sense of prevention of physical waste which will be dealt with under subheading (i) below. They also include conservation in the sense of upgrading resources within the Province. This aspect is dealt with under subheadings (ii) to (iv) below.

(i) Prevention of Physical Waste at the Proposed Plant.

(ii) Suitability of a Two-Stage Plant and Possibility of Reprocessing the First Stage Outlet Gas.

(iii) Potential Ethane Recovery.

(iv) Potential Helium Recovery.

The question of the need for a third processing plant in the Empress area also has conservation connotations. However, the Board has decided to deal with that matter as a separate issue.

(b) Environmental Considerations

(c) Other Related Considerations

In addition to the conservation and environmental matters which are normally considered as part of an application under section 38 of The Oil and Gas Conservation Act, the Board believes that the following matters, which were raised in interventions, have a bearing on the subject application:

(i) Need for a Third Processing Plant in the Empress area and the Possibility of a Common Processor Declaration.

(ii) Need to Condition Approval Respecting Volume to be Processed for Liquid Recovery.

(iii) Need for Removal Permits and Export Licences.

7.0 CONSERVATION CONSIDERATIONS

7.1 Prevention of Physical Waste at the Proposed Plant

7.11 Views of Consolidated

Consolidated indicated that it would initially install an adsorption type processing plant which it would purchase and dismantle in Michigan, move into the Province, and reassemble at Empress. The first stage of the plant would process all of Consolidated's gas and recover about 17 per cent of the propane and essentially all of the butanes and heavier hydrocarbons contained in the raw gas. This would result in production of some 2,000 barrels per day of a propane plus liquid mix. The ultimate plant, which would be built in conjunction with the first stage but would not be completed until approximately 1 year after the first stage was in operation, would recover some 90 per cent of the propane and all of the heavier hydrocarbons contained in the raw gas or 3,900 barrels per day of a propane plus mix. It would be a turbo expander type of plant.

Consolidated submitted that there would be no flaring or venting of hydrocarbons from the proposed plant under normal operating conditions. It stated that the planned facilities would achieve essentially 100 per cent conservation of the gas entering the plant. Fuel requirements for the initial stage of the plant would total 1.1 million cubic feet per day or 0.3 per cent of the total gas delivered to the plant. The ultimate plant, consisting of stages 1 and 2, would consume 2.83 million cubic feet per day of fuel or approximately 0.81 per cent of the total gas delivered to the plant. Consolidated indicated that in the event of an emergency plant upset the vapours would be flared and the liquids would be disposed of to an underground storage tank. Flaring of vapours would be minimized by immediately by-passing the plant with the gas in Trunk Line and flaring only the gas which would be within the plant itself.

Consolidated stated, in response to a suggestion that the first stage plant would not perform as predicted because it was designed for gas of a different composition, that the plant would be capable of recovering 17 per cent of the propane and essentially all of the butanes and heavier components contained in the gas entering the plant.

7.12 Views of Dome

Dome stated an opinion that the first stage plant might not be capable of achieving the proposed levels of liquid recovery because the plant had been designed and built to process a gas of a different composition than the gas which would be processed at Empress. Dome further contended that the age of the plant might have an adverse effect on conservation.

7.13 Views of Others

The other interveners did not comment on this matter.

7.14 Views of the Board

The Board is satisfied with the planned conservation levels within the proposed plant. Respecting the Dome suggestion that the first stage of the plant might not perform as intended due to age or because the facilities had been designed for gas of a different composition, the Board is prepared to accept the Consolidated statement that the facilities could be operated to meet planned conservation levels. If an approval for the scheme is issued, the Board would expect Consolidated to take whatever action might be required to meet the conservation requirements spelled out in the approval.

The Board considers the fuel requirements for the first and second stages of the plant to be reasonable. The question of whether fuel could be saved on an overall basis by processing the Consolidated gas in existing processing plants in the area is dealt with in a later section of the report.

7.2 Suitability of a Two-Stage Plant

7.21 Views of Consolidated

Consolidated stated that the expected recovery in the first stage plant would be 17 per cent of the propane and essentially all of the butanes and heavier components. It further stated that the expected recoveries in the ultimate plant would be 90 per cent of the propane and essentially all of the butanes and heavier components. In reply to questioning, Consolidated stated that staging the plant is probably not the most economical method of building the plant and was not its first choice. It said that in order to meet contractual and time limitations it was deemed necessary to build the plant in stages.

Consolidated agreed that as a result of the staging, approximately 70 per cent of the ultimately recoverable propane would not be recovered as a liquid product during the first year of operation but rather would be left in the gas stream leaving the plant. It was stated by Consolidated that it would be technically and physically possible to reprocess the residue outlet gas from the first stage of its plant in existing plants to recover the remaining propane contained in the gas. Consolidated also stated that it would be willing to enter into negotiations with the owners of the existing plants to have the residue gas reprocessed on a short-term basis.

7.22 Views of Dome

Dome stated that the loss of propane, which it estimated to be 750,000 barrels during the period when only the first stage of the Consolidated plant would be operating, is not acceptable conservation. It further contended that the first stage plant might not achieve the recovery levels outlined by Consolidated which would result in an even greater loss of propane.

Dome stated an opinion that staging the plant is not the most economic method of constructing the plant. Regarding the possibility of Dome reprocessing the residue gas from the Consolidated plant for the additional recovery of propane, Dome stated that such processing would be technically feasible but that it would be more expensive to process the lean residue gas than unprocessed pipe line gas. Dome indicated that it had not determined whether reprocessing the residue gas would be economic.

7.23 Views of TransCanada

TransCanada stated that since the initial plant does not maximize liquid recovery, which is contrary to good conservation practice and to TransCanada's contract with Consolidated, the Board should deny the application.

7.24 Views of Others

None of the other interveners commented on this matter.

7.25 Views of the Board

Approval of the applied for facilities could mean that the recovery within the Province of propane as a liquid would be reduced by more than 2,000 barrels per day for a period of approximately one year. However, this would not be a conservation loss but rather would be a lack of upgrading of resources within the Province which might otherwise occur. The propane in question would remain in the gas stream leaving the Province and in this form would retain value consistent with its contribution to the volume and heating value content of the gas being removed from the Province. For this reason, and because the reduced propane recovery would be a temporary situation while the second stage of the plant is being constructed, the Board would not deny the subject application due to the reduced propane recovery.

With respect to the question of further processing the residue gas in an existing plant, the Board recognizes that depending on the costs of further processing and the demand for propane, such action might be desirable from an Alberta viewpoint. The Board is satisfied that if additional propane were recovered, this propane or its equivalent would be moved out of the Province. Accordingly, meeting Alberta's requirements for propane would not be affected. The Board thus considers that the question of further processing of the residue gas should be left to the parties involved to negotiate a suitable arrangement if further processing appears desirable.

7.3 Potential Ethane Recovery

7.31 Views of Consolidated

Consolidated indicated that by modifying the second stage plant, it would be technically feasible to recover up to 60 per cent of the ethane contained in the gas. Such recovery would be as an ethane plus mix, but it would be feasible to recover a pure ethane product with further modifications to the plant.

Consolidated stated that it does not propose to recover ethane at the present time because it has no market for the product. If a market for ethane should develop, recovery of ethane would commence. In such case, according to Consolidated, the amount of ethane which could be recovered might have to be reduced from 60 per cent due to a contractual limitation on the minimum heating value of the residue gas leaving the Province.

7.32 Views of Dome

Dome stated that plans exist for processing gas leaving the Province at Empress for the recovery of ethane. Consequently, if Dome were to process the Consolidated gas, it would be part of the overall stream from which ethane would be recovered.

7.33 Views of Others

The other interveners did not comment on this matter.

7.34 Views of the Board

The Board agrees with Consolidated that, at the present time, there is not a market for the ethane contained in the gas stream to be processed and consequently, there is no reason to recover the ethane. The Board is satisfied that if a market for the ethane does materialize, the proposed facilities are such that, with modifications, the ethane could be recovered either in an ethane rich stream of liquids or as essentially pure ethane. The Board, however, notes that the economics of ethane recovery would likely be more attractive and the likelihood of ethane recovery would increase if the gas in question were to be processed at an existing plant rather than at the proposed plant.

7.4 Potential Helium Recovery

7.41 Views of Consolidated

With respect to the possibility of helium recovery, Consolidated stated that it would be technically feasible to modify the proposed plant for the recovery of helium. It went on to say that since it is not economic to recover helium under present conditions, such recovery is not part of the application.

7.42 Views of the Interveners

None of the interveners commented on this matter.

7.43 Views of the Board

The Board is in agreement with Consolidated that it is currently uneconomic to recover helium from the subject gas stream. The Board notes that, given favourable economics, helium could be recovered in future by modifying the plant. Bearing in mind the relatively small size of the proposed facilities and the low helium content of the gas to be processed, the Board doubts that helium recovery at the facilities would ever become economic.

8.0 ENVIRONMENTAL CONSIDERATIONS

8.1 Views of Consolidated

Consolidated stated that since the gas is sweet, problems with respect to sulphur emissions or odours are not anticipated. Consolidated indicated that there would be no flaring or venting of hydrocarbons during normal operations and, in the event of an emergency, flaring would be conducted in a smokeless manner. Process waste water would be collected and disposed of to an underground formation. With regard to surface water runoff control, Consolidated stated an opinion that due to the arid nature of the land surrounding the plant, surface runoff would not occur. It did not propose to install runoff control facilities.

In reply to questioning relating to the noise level which would occur at the Pacific housing site, Consolidated stated that the noise level from its proposed plant would be insignificant in relation to the noise level of the Dome plant which is much larger and approximately equidistant from the houses.

Consolidated stated that its plant would be designed to meet all environmental regulations and requirements.

8.2 Views of Dome

Dome questioned the environmental adequacy of the first stage plant because of its age. It suggested an increased potential for accidental emissions or spills and drew attention to the effect they would have on the environment.

8.3 Views of Pacific

Pacific questioned whether the location of the proposed Consolidated plant would raise the noise level at its nearby housing complex.

8.4 Views of Others

The other interveners did not comment on environmental matters.

8.5 Concerns of the Department of the Environment

Although the Department was not represented at the hearing, concern was expressed regarding the proposed lack of surface water runoff control. The Department indicated that it would require surface water runoff control facilities to be installed at the proposed plant.

8.6 Views of the Board

The Board is generally satisfied that the proposed facilities would meet environmental standards. The Board appreciates the view of Dome that the older facilities utilized in the first stage of the plant might increase the difficulties of adhering to the standards but accepts the undertaking of Consolidated that the environmental conditions of any approval would be met. Such conditions would include provision for surface water runoff control facilities as required by the Department of the Environment.

The Board expects, as was suggested by Consolidated, that the noise level at the Pacific houses would not noticeably increase as a result of the proposed facilities. In any case, the Board has noise level requirements which would have to be satisfied if the applied for facilities are constructed and placed in operation.

9.0 OTHER RELATED CONSIDERATIONS

9.1 Need for a Third Processing Plant in the Empress Area and the Possibility of a Common Processor Declaration

9.11 Views of Consolidated

Consolidated acknowledged that the construction of a third processing plant in the Empress area was probably not the most efficient approach to having its gas processed. Consolidated stated that when it became apparent that it would be economic to recover liquid hydrocarbons from the gas it is removing from the Province, it approached the owners of existing processing facilities in the Empress area. Since capacity to process the gas was available, Consolidated believed it would be best if an arrangement could be made to have its gas processed in one of the existing plants and thus not idle existing capacity. Consolidated stated that it would have made a long-term arrangement whereby the Consolidated gas could be processed through the existing facilities and the facilities expanded as necessary, or a short-term arrangement whereby Consolidated would construct its own facilities if existing capacity was required by others in future. Consolidated stated that the owners of existing facilities did not express interest in entering into arrangements to process Consolidated's gas.

In reply to questions by Dome, Consolidated clarified its statement by indicating that Dome was not prepared to discuss an arrangement whereby the Consolidated gas would be processed prior to the end of 1974. Consolidated stated that since it must be processing its gas not later than December 28, 1974, or lose the right to process it, this precluded further discussions with Dome.

Consolidated indicated that if the existing plants were declared common processors with respect to the gas in Trunk Line, many of the problems raised by the application could be avoided. Consolidated went on to say that it had looked at the common processor provisions of The Oil and Gas Conservation Act and had concluded that the section of the Act referred to gas processing plants in the field rather than to the kind of facility that now exists at Empress.

9.12 Views of Dome

Dome submitted that the processing plant proposed by Consolidated was not required since existing plants have capacity to process the gas in question. It contended that the proposed plant would in all probability use more fuel than is now being used to recover the same volume of liquids. Dome went on to say that it would not be good conservation practice to utilize manpower, man-hours and resources to move an existing facility from Michigan to Alberta which would recover less liquids than the existing extraction plants and which might, in fact, be partially obsolete at the end of one year.

Dome stated, in response to a statement by Consolidated, that due to limitations in the Dome contract with TransCanada, it was not possible to negotiate a contract with Consolidated to process the Consolidated gas prior to the end of 1974.

With respect to the common processor question, Dome indicated that a common processor arrangement would solve many of the problems raised by the application. It did not, however, clearly state whether it considered that the common processor section of The Oil and Gas Conservation Act would be applicable to plants processing pipe line gas. It stated opposition in principle to the Board, at any time, abrogating the contractual rights of the parties that appeared before it. Dome added that if the Board should name a common processor, Dome would of course comply.

9.13 Views of Others

None of the other interveners expressed views respecting this matter.

9.14 Views of the Board

The Board agrees with Dome that the addition of a third processing plant in the Empress area, particularly one which would idle processing capacity at the existing plants, does not make the best sense because it would probably result in the use of additional volumes of fuel gas to recover the same volumes of liquids. Also, the utilization of capital and human resources to construct additional processing facilities, part of which may be idled within one year, would not be desirable from a conservation of capital and human resources viewpoint. In this respect, the Board considers it relevant that Consolidated did not question that its proposal is probably not the most efficient approach to having its gas processed.

The Board recognizes that with the existing contractual situation it is not likely that a voluntary processing arrangement involving the existing plants would be feasible. For this reason, the Board has considered the possibility of declaring the owner of one or other of the existing processing plants to be a common processor as provided for in The Oil and Gas Conservation Act. The Board notes that both Consolidated and Dome indicated that a common processor arrangement could provide a solution to the existing problem. The Board is of the view that the existing common processor provisions of The Oil and Gas Conservation Act apply to field processing plants but may not apply to pipe line gas processing plants. Additionally, the Board has not received an application to declare a common processor and therefore may not proceed on such matter. The Board recognizes that it could seek amendment to the existing legislation to ensure the power to declare a common processor with respect to gas passing through a particular pipe line. The Board has decided against such a move at this time.

Since the Board has decided not to pursue declaring the owner of an existing plant to be a common processor, the question arises as to whether the Board should refuse to grant an approval for the proposed plant because using an existing plant would be more efficient. In the Board's view, it should not interfere with the rights of individuals to produce or process their own resources through separate facilities, even though such an approach might not be the most efficient, except where serious conservation losses would occur. The Board considers that the waste that would occur as a result of the Consolidated proposal would be the likely use of extra fuel to recover the same volume of liquids. The incremental fuel usage would be small compared to the overall volumes of gas being processed. For this reason, the Board is not prepared to deny the Consolidated application on grounds that a third plant in the Empress area is not needed. At the same time, the Board wishes to emphasize that it considers the construction of a third plant to be an inefficient approach to the problem and urges the parties involved to work towards a voluntary arrangement which would not involve additional processing facilities until such time as they are clearly needed.

9.2 Need to Condition Approval Respecting Volume to be Processed for Liquid Recovery

9.21 Views of Dome

Dome submitted that if approval is given to Consolidated, in order to maximize liquid propane recovery, the inlet volume to stage one of Consolidated's plant should be reduced so that a minimum of 90 per cent of the propane contained in the gas would be recovered.

9.22 Views of Consolidated

Consolidated stated that the maximum volume of gas to be processed should not be limited to maximize liquid recovery since the plant would ultimately achieve a product recovery level similar to those plants already in existence.

9.23 Views of Others

The other interveners did not comment on this matter.

9.24 Views of the Board

Any approval issued by the Board would contain a clause limiting the maximum volume of gas which may be processed in the plant. This maximum would relate primarily to the plant capacity. With regard to further reducing the maximum permitted volume of gas which may be processed in the proposed facilities, the Board believes that any adjustment arising from the exchange and commingling of gas should be made by Trunk Line pursuant to The Alberta Gas Trunk Line Company Act.

9.3 Need for Removal Permits and Export Licences

9.31 Views of Dome

Dome stated that the proposed plans could not be implemented without removal permits and export licences.

9.32 Views of Consolidated

In Consolidated's opinion, the need for removal permits and export licences for the products recovered at its plant is beyond the scope of an application made pursuant to section 38 of The Oil and Gas Conservation Act.

9.33 Views of Others

The other interveners did not comment on this matter.

9.34 Views of the Board

The Board is in agreement with Consolidated that the need for removal permits and export licences is beyond the scope of this application.

10.0 DECISION

The Board has decided to grant the application by Consolidated for approval of a scheme for the construction and operation of a gas processing plant in the Empress area. Approval No. 2007 is issued concurrently with this report.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

Dated at Calgary, Alberta,
April 8, 1974

ENERGY RESOURCES CONSERVATION BOARD

Interim Decision
Application No. 7372

PROCESSING PLANT ON PLAINS DIVISION OF THE ALBERTA GAS TRUNK LINE COMPANY LIMITED SYSTEM

The Energy Resources Conservation Board, at a public hearing held on February 5 and February 6, 1974, in Calgary, Alberta, considered an application by Consolidated Natural Gas Limited, made pursuant to section 38 of The Oil and Gas Conservation Act, for approval of a scheme to construct and operate a gas processing plant in the Empress Area. The plant, to be located in the North-east quarter of Section 2, Township 20, Range 1, West of the 4th Meridian, would be designed to, initially, process 350 million cubic feet per day of marketable pipe line gas for the recovery of 346 million cubic feet per day of residue gas and 2059 barrels of propane plus mix. Ultimately the plant would process 350 million cubic feet per day of raw gas, for the recovery of 341 million cubic feet per day of residue gas and 3900 barrels of a propane plus mix.

The Board has decided to grant the application and proposes to issue to Consolidated Natural Gas Limited a formal approval for the scheme. The Board's approval will be subject to the conditions normally stipulated for gas plants and if and when approval of the application, as it affects matters of the environment, is received from the Minister of the Environment, the approval will be issued.

A formal Board Decision Report, summarizing the evidence adduced and the reasons for the decision, will be issued in the near future.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
April 3, 1974

ENERGY RESOURCES CONSERVATION BOARD

DECISION 74 - 5
PROCEEDING NO. 7625

IMPACT OF PETROLEUM ACTIVITIES IN IRRIGATION AREAS

1.0 BACKGROUND AND HEARING

In late 1973, the Board was made aware of the impact that petroleum developments have on irrigation operations in south-eastern Alberta. At that time a number of landholders objected to an application made by Merland Explorations Limited. The application requested that the normal drilling spacing units for gas wells completed in the Milk River and Medicine Hat Formations in certain lands in the Bantry Field be reduced to one-quarter section with target areas located in the centers of quarter sections. The lands contained in the Merland application were all within the Eastern Irrigation District and most of the lands were being irrigated. The Board also received objections from landholders when it published notice respecting two similar applications made by PanCanadian Petroleums Limited for certain lands in the Alderson Field. These lands were again within the Eastern Irrigation District but the majority of the lands contained in PanCanadian's applications were not under irrigation. The primary objection to the Merland and PanCanadian applications was that the proposed central target area would interfere with current and possible future irrigation operations.

As a result of the objections to the Merland application the Board directed that examiners hear the application and the objections raised by the landholders. At the hearing, the landholders made the point that the central target areas which Merland had applied for could disrupt an entire irrigation system for a field. The landholders suggested that the target areas for these wells be relocated in the north-east corner of the quarter section. In their report to the Board the examiners recommended that Merland's application be granted. Additionally, the examiners recommended that the Board consider setting up a committee composed of representatives from the petroleum and agricultural industries along with representatives of government organizations to determine solutions to the problem of inter-industry interference in irrigation areas. As a result of the examiners' recommendation, the Board called the subject hearing to consider the matter of inter-industry interference in irrigation areas.

The matter was heard by the Board in Brooks, Alberta, on March 21, 1974, with D. R. Craig, P. Eng., V. Millard, and G. J. DeSorcy, P. Eng., sitting.

2.0 APPEARANCES

The following made appearances at the hearing:

	Represented by
The Eastern Irrigation District Landholders Association (Irrigation Association)*	Don Alberts Steve Merkl
Sam Alberts	Sam Alberts
Jim Hajash	Jim Hajash
The Board of Directors of the Eastern Irrigation District (E.I.D.)	C.A. Saunders Mr. Hoffman
Alberta Department of Agriculture (The Department of Agriculture)	J.C. Purnell, P. Eng.
Alberta Eastern Gas Limited (Alberta Eastern)	Lorne Leverson, P. Eng.
PanCanadian Petroleum Limited (PanCanadian)	C. Miller W.S. Bishai, P.Eng. G.A. Montemurro, P.Eng. H.D. Woodkey, P.Eng
Chevron Standard Limited (Chevron)	L.C. Zerr, P.Eng
Board Staff	R.G. Evans, P.Eng A.L. McLarty I.F. Taylor, E.I.T.

Chevron appeared only for purposes of examining witnesses and presenting closing argument.

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*Abbreviations in brackets are used throughout report.

3.0 MATTERS FOR CONSIDERATION

The initial matter that requires the Board's consideration is

(a) The area of the Province to which any decisions resulting from Proceeding No. 7625 would be applied.

Additionally, the Board advised in the Notice of Hearing that it would consider the following matters:

(b) The impact on agricultural operations of centrally located target areas for oil and gas wells and the feasibility of relocating target areas to reduce such impact; and

(c) The impact on agricultural operations of current surface completion practices for oil and gas wells and the feasibility of modifying current practices to lessen such impact.

It should be noted that there was general agreement at the hearing that a change in target area could only be considered for undrilled spacing units. Therefore the Board emphasizes that any decision as a consequence of these proceedings would only be applicable to undrilled spacing units.

At the hearing, other matters relevant to the operation of the petroleum industry in irrigation areas were raised. The Board considers that certain of these matters are within the jurisdiction of other government agencies, and others are within the Board's jurisdiction. The Board believes that the latter should be dealt with in this report. They are as follows:

(d) The question of giving notice for well licences and changes in spacing regulations;

(e) Industry practices regarding the construction of pipe lines; and

(f) Industry practices regarding the drilling of wells.

Regarding point (d), the Board has carried out a review of its policies regarding the licensing of wells on a basis separate from the subject hearing. As a result of this review the Board will initiate important procedural changes which will provide the surface landowner with an adequate opportunity to make representations respecting a proposed well location before a drilling licence is issued. The Board believes that the impending changes to the well licensing procedure are particularly relevant to the determination of the matters considered at the hearing in Brooks. For this reason the Board will deal first with the impending changes regarding the licensing of wells.

4.0 LICENSING OF OIL AND GAS WELLS

4.1 Views of Irrigation Association

The Irrigation Association stated that it would be advantageous if notices of application for drilling permits could be published in the local newspaper of the area involved. Furthermore, the Irrigation Association expressed a view that, before granting drilling permits, xhe Board should give notice of the proposal in local newspapers, detailing the proposed specific locations of the wells at least 14 days in advance of the time when a landowner would be contacted by a landman to acquire a surface lease. The Irrigation Association said that it believes that land acuisition activity related to a drilling program should be handled in the same manner as pipe line construction activities insofar as land acquisition practices are concerned.

4.2 Views of Petroleum Industry

Some representatives of the petroleum industry present at the hearing stated xhey would be opposed to the Board publishing notice prior to granting drilling licences. The basis for their objection was the time lag that would be involved if the Board adopted such a procedure.

4.3 Views of the Board

The question of licensing of wells was raised by the Irrigation Association, but the Board was in the process of reviewing its licensing policies separate from the subject hearing. Having completed this review, the Board has decided to revise its well licensing procedures. These revised procedures will ensure that each affected land surface owner is aware of an application for a licence to drill a well on his land, prior to the well licence being issued. The Board believes that this will ensure that each land surface owner has a reasonable opportunity to make representations to the mineral owner and to the Board, with respect to the most suitable surface location for the well within the prescribed target area.

Accordingly, effective June 1, 1974, the Board will require each applicant for a well licence to include in the application, evidence satisfactory to the Board, of a right to drill on the proposed land surface location. Where such evidence is provided, whether by surface agreement or otherwise and where the application is otherwise in compliance with the provisions of xhe regulations, the Board will grant the licence without delay. Where, however, the well licence application is incomplete as to evidence of a right to drill on the proposed surface location, the Board would notify the land surface owner of the application and would forward to the land surface owner a copy of the well licence application and survey plan, indicating the exact location of the proposed well. The Board would then allow a minimum period of 10 days, during which the land surface owner would have an opportunity to submit to the Board objections, either in writing or orally to be confirmed in writing, as to the proposed location of the well. If no objection is filed the Board would grant the application. If objection is filed, it would be considered by the Board in relation to the merits of the location proposed by the applicant. Following consideration by the Board of the application and objections thereto, a well licence would be issued either for the original location proposed if such is essential to the recovery of a mineral deposit or for a reasonable alternative location. Where the surface location of the well results in disruption to surface operations, whether the disruption be minor or major in nature, the matter of adequate compensation therefore is exclusively the jurisdiction of the Surface Rights Board.

Although this policy will not be restricted to the area under consideration in the subject proceeding, but will be applicable to the Province as a whole, the Board believes that it will be a significant step in the direction of minimizing interference between the mineral and land surface owners. Specifically, this new procedure related to issuance of drilling licences should help to alleviate many of the problems caused by oil and gas drilling activities in irrigation areas.

5.0 AREAS OF THE PROVINCE TO BE CONSIDERED

5.1 Views of Board Staff

The Board staff submission outlined areas in which it considered inter-industry conflict could arise. These areas are lands within the 14 Provincial Irrigation Districts where oil and gas development is occurring or can be expected. The Board staff expressed a view that the lands contained within the 14 Provincial Irrigation Districts represented all the potentially irrigable land in Alberta.

5.2 Views of Department of Agriculture

The Department of Agriculture submitted the results of a preliminary study which indicated that the areas of potential irrigation development in Alberta are much more extensive than those shown in the Board staff submission. Currently in Alberta some 800,000 acres of land are under irrigation within developed Irrigation Districts, out of a potential 1,500,000 acres of irrigable land. The Department of Agriculture stated that preliminary examination of future potential for irrigation outside the organized districts shows that an additional 3,000,000 acres of land south of the Red Deer River may be irrigable.

5.3 Views of Others

Other parties who made submissions at the hearing did not refer to specific areas of the Province. However, all parties generally directed their comments towards areas of irrigation activity.

5.4 Views of the Board

The Board notes that the Department of Agriculture considers the majority of land south of the Red Deer River to be potentially irrigable. The Board believes that any decisions respecting this hearing should be made applicable to all lands in Alberta east of the 5th Meridian in Townships 1 to 30 inclusive. Such lands are shown on Attachment 1. The adoption of this area would not preclude adding or deleting lands as new information or other relevant evidence becomes available.

6.0 SURFACE LOCATION OF OIL AND GAS WELLS

6.1 Views of Board Staff

The Board staff stated that the Board's reasons for designating normal well locations in the center of a drilling spacing unit were twofold:

(a) To ensure uniform drainage of the reservoir by requiring a uniform distance between wells, and

(b) To preserve equity among mineral owners, by ensuring that one owner does not unduly encroach upon the mineral rights held by others.

The Board staff also identified some particular problems which might be encountered if the surface location of oil wells were to be located other than in the center of the existing drilling spacing units. It explained that the crude oil found in south-eastern Alberta is generally more viscous than crude oil found elsewhere in the Province. In the development of fields having high viscosity crude it is not unusual to require up to four wells per quarter section to adequately drain the reservoir. Such a high well density could greatly increase the interference to farming. Also, because oil wells in south-eastern Alberta frequently must be pumped in order to bring the oil to the surface, and since the pumping mechanisms usually include large pump jacks, the wellhead installations can be major sources of interference. Further, if a pumping mechanism is used, the well bore must be as straight as possible to avoid excessive wear on pump rods and casing. This generally precludes the possibility of directionally drilling the wells.

The Board staff submission explained that unitization of several spacing units in a parcel of land before development could partially solve the problem of inter-industry interference. It pointed out that the Board has the power to waive spacing regulations for lands contained in a unit by issuing a Miscellaneous Order. The Board staff went on to state that unitization is not normally initiated until after the development of a particular tract of land has been completed. It said that for this reason unitization would not be a practical solution to the interference problem in most instances.

6.2 Views of Irrigation Association

The Irrigation Association recommended that normal target areas for wells be moved from their present central location to a location which would be as close as possible to the corner of sections or quarter sections. The Irrigation Association submitted that if this change were made for a large area of land, uniform drainage patterns for oil and gas extraction would still be maintained.

The Irrigation Association stated that since the majority of farmers conform to the quarter section in their operations, corner target areas would minimize the problem caused when fields are divided up with wellsites and access roads. Wellsites would still pose some problems to the farmers but the corner target area would be much more acceptable. Oil and gas companies would also benefit if corner target areas were instituted since less land would be required for access roads.

In support of its submission, the Irrigation Association filed some technical data dealing with the operation of irrigation sprinkler systems. This data supported the Irrigation Association's position that if obstructions in fields did not preclude the operation of sprinkler systems, the obstructions would at any rate require that the farmer invest additional time and money to make the system operable.

6.3 Views of Sam Alberts

Mr. Alberts' submission dealt mainly with problems petroleum development could cause for flood type irrigation systems. He stated that wellsites located in the center of fields leave blind spots in the field which cannot be irrigated. These blind spots arise because it is very difficult to flow water around a wellsite leaving the irrigation ditches on the downhill side of the wellsite useless. Mr. Alberts stated that well locations on the corners or outer edges of the quarter sections would minimize the interference he spoke of. He said that this practice would also save time and expense for oil companies in that the lease road would no longer require numerous culverts to maintain the water flow down the field.

6.4 Views of Jim Hajash

Mr. Hajash stated that current oil and gas well locations on irrigated land are a nuisance to irrigation farming. Mr. Hajash went on to detail specific operating problems that the well would cause. He explained that with a gas well situated in the middle of the field it would be necessary to let the water run to the wellsite and then to construct another ditch around the wellsite to redistribute the water below the well. Mr. Hajash stated that this procedure entails significant amounts of time-consuming labour. He said that during irrigation season, time is valuable since when crops need irrigating they deteriorate very quickly if water is not applied. In summary, Mr. Hajash stated that if wells were located in the corners of quarter sections they would constitute much less nuisance to irrigation operations.

6.5 Views of E.I.D.

The E.I.D. submitted that wellsites located in the middle of an irrigated field are a nuisance and an inconvenience for the farmer. The E.I.D. said that wells have an especially serious effect on fields that have been levelled for irrigation purposes and also in cases where sprinkler equipment is used. The wellsites make it necessary for the irrigation farmer to invest extra time and expense to make his system operable. It therefore recommended that wells in future be located along or as closely adjacent to the original grid survey lines as possible.

6.6 Views of Department of Agriculture

The Department of Agriculture stated that the use of sprinkler systems for irrigation of large tracts of lands is expected to increase in the future. Sprinkler systems use approximately one-quarter of the water that flood irrigation systems use to irrigate the same crop. The Department of Agriculture stated that this higher efficiency of sprinkler systems would likely increase their popularity in future as available water resources become scarce.

As a result of present irrigation trends in Alberta, the Department of Agriculture suggested that present target areas be shifted to the corner of the quarter section. Furthermore, it recommended that the Board specify some specific target area to enable the farmer to adequately plan his irrigation developments to allow for possible oil and gas activity on his land.

6.7 Views of Alberta Eastern

Alberta Eastern addressed itself only to shallow gas development in irrigation areas.

Respecting gas wells drilled on the basis of one section spacing, Alberta Eastern stated that the current regulations did not require change. It said that the present regulations allowed the operator sufficient flexibility to locate a well out of the way of irrigation operations near the middle of the section. Alberta Eastern stated that in this case no equity problems would be created by the well's location.

Alberta Eastern recommended that for quarter-section spacing, the normal target area be shifted to the north-east corner of the quarter section and for half section spacing, the target area be in the corners of offsetting diagonal quarter sections. It recommended that a target area size of 1320 feet by 1320 feet be maintained. This target area size would give the operator some flexibility to move the well location up to 1320 feet in two directions along the edge of the quarter section to remove it from buildings or other surface improvements. The well could still remain adjacent to the road allowance. In response to questioning, Alberta Eastern stated that it would be willing to switch to a north-east corner target area for a particular development even if it had partially developed those lands on the basis of central target areas.

Alberta Eastern stated that its corner target area proposal would allow for a symmetrical drainage pattern. It conceded that the proposed north-east target could create some potential lease line drainage problems, but stated that any lease line losses would likely balance out and in the end would be insignificant. In closing, Alberta Eastern stated that it would be prepared to accept minor lease line equity problems in return for greater freedom of lease location.

6.8 Views of PanCanadian

In its submission, PanCanadian categorized its petroleum operations in south-eastern Alberta into three categories. It then dealt with each category separately.

The first category PanCanadian discussed was shallow gas wells. It said that the well sites for shallow gas wells could be located in such a manner as to minimize problems of interference with agricultural operations in irrigation areas. The regulations for these wells could be altered to give the operator ultimate flexibility in locating wells to suit the surface landowner. This alteration would not have an adverse effect on adjacent mineral owners. Failing the implementation of the preceding recommendation, PanCanadian recommended that spacing regulations for shallow gas wells be altered to allow the well to be located as close to the corner of the quarter section as possible. These corner locations would not have an adverse effect on reservoir performance. No particular corner of a quarter section should be specified. PanCanadian initially stated that a transition or buffer zone should be established between areas with central well sites and areas with corner wellsites to protect offset mineral owners. However, in response to questioning, it stated that if no penalty factors were applied by the Board to wells completed near the edge of quarter sections, the transition zone would not be required.

Secondly, PanCanadian discussed gas wells that produced from formations below the Milk River. Regarding these wells PanCanadian expressed a view that the present regulations give the operator sufficient flexibility in locating the well to satisfy the needs of the agricultural industry.

Finally, PanCanadian discussed oil development in south-eastern Alberta. The oil reservoirs found in south-eastern Alberta are often narrow serpentine channel sands and therefore there is a need for flexibility in locating wells when developing these pools. In order to adequately drain these pools and to maintain an economic operation, experience has demonstrated that more than one well per quarter section is necessary. To ensure good conservation, these wells must be located so as to provide a regular drainage pattern. These regular drainage patterns are also important to certain types of enhanced recovery schemes such as pattern water floods. In summary, with regard to target areas for oil wells, PanCanadian said that a well located anywhere other than the center of the drilling spacing unit would cause inequitable drainage from the surrounding lands.

6.9 Views of Chevron

In closing argument, Chevron stated that its main involvement in south-eastern Alberta is with oil development. It contended that oil development is much less flexible than gas development in the location of wellsites.

6.10 Views of the Board

At the hearing, the general concept of target areas offset from the center of quarter sections received favourable reaction, at least for shallow gas wells, from virtually all parties involved. There was some discussion regarding the best way in which target areas could be changed from the center of the quarter sections. This discussion centred around the following three methods:

(a) Unitization of several parcels of land with a subsequent suspension of the relevant sections of the Regulations which specify target areas;

(b) Complete flexibility of target areas for the development of certain gas zones; and

(c) Target areas located in the corner of the quarter section.

Respecting method (a), the Board notes that unitization does not normally take place before a particular pool has been extensively developed. The wells drilled before a target area suspension order may be issued are in most cases drilled within the target area stipulated by the Board. For this reason, the Board's opinion is that unitization alone cannot be a significant factor in alleviating the problem of inter-industry interference in irrigation areas.

Respecting method (b), the Board believes that if a target area is not specified, a haphazard array of wells could result. This would, to an extent, act against correlative rights and conservation. Furthermore, specifying a uniform pattern of target areas would enable farmers to plan their developments with some foresight regarding potential petroleum developments. For these reasons, the Board does not accept the concept of complete flexibility for well locations as suggested by PanCanadian.

Representatives from both the petroleum and agricultural industries generally were of the view that, if target areas could be moved to the corners of quarter sections, many of the interference problems encountered in irrigation areas could be minimized if not entirely eliminated. The Board concurs with this view and is prepared to institute corner target areas for the overall decision area which would result in most wells being drilled in the corners of quarter sections. The Board would make exceptions and approve other target areas for those cases where it could be shown that corner target areas would adversely affect efficient reservoir drainage or where other legitimate reasons exist.

The Board gave serious consideration to the possibility of substantially reducing the size of target areas in irrigation areas. This possibility was considered in an effort to ensure that future wells would be located such as to minimize their interference on present and future irrigation operations. The Board also considered a triangular target area located in the north-east corner of the drilling spacing unit. The Board believes that, in most instances, a well located within a relatively small triangle in the corner of a quarter section would have minimal impact on existing forms of irrigation. However, as a result of the modifications to the requirements for obtaining a well licence, discussed in Section 4 of this report and given the adoption of target areas in the corner of quarter sections, the Board believes that reducing the size or changing the shape of the target area would be an unnecessary restriction. The landowner will have an opportunity to object to a proposed well location before a well is licensed. With this option, the landowner in consultation with the industry and the Board can ensure that a well location will have the minimum interference with irrigation operations. Furthermore, the Board recognizes that not all the areas included in its decision area are irrigable lands. In fact, the terrain of some of the areas included in this decision may be such that an operator requires a great deal of flexibility in the surface location of the well simply to obtain a suitable location. Finally, in some special cases the flexibility produced by the present generous-sized target area may allow the operator to locate a well in an area which would be more suitable to the landowner.

The Board's overall approach to the problem of surface locations of oil and gas wells will thus be to alter target areas so that whenever possible wells will be in the corner of quarter sections. The Board anticipates that this decision in conjunction with its changed well licensing procedures will greatly reduce inter-industry interference problems in irrigation areas. The details of the Board's intended target area changes for gas and oil for various sizes of drilling spacing units are summarized in the following sections of the report.

Gas Zones

The Board's present regulations prescribe a target area for a normal one section drilling spacing unit to be an area within the section having sides 1320 feet from the sides of the drilling spacing unit and parallel to them. The resulting target area is comprised of legal subdivisions (L.S.D.'s) 6, 7, 10 and 11. The Board believes that in most instances this large area should give the operator sufficient flexibility to locate a well near the corner of a quarter section to alleviate irrigation interference problems. The Board therefore will not make any change to the target area now prescribed for a normal one section drilling spacing unit.

For smaller drilling spacing units of a half section or a quarter section the normal target area has been an area having the dimensions of 1320 feet by 1320 feet located centrally in a quarter section. The Board has decided to change the location of these target areas so that in future the target areas will be in the north-east corner of the quarter section. Thus, the target areas for half section spacing will be L.S.D.'s 6 and 16. The target areas for quarter section spacing will be L.S.D.'s 6, 8, 14 and 16. These target areas for new gas wells are shown on Attachment 2.

The Board realizes that the non-central target areas for half section and quarter section spacing could create potential equity problems. However, the Board is of the view that since reduced drilling spacing unit sizes are normally required for low productivity formations, lease line drainage should not be large and would tend to balance out over any large area.

The Board recognizes that its current approach to calculating penalty factors for off-target wells would no longer be applicable if the target areas are changed to the corners of drilling spacing units. It follows that revised procedures for calculating penalty factors would have to be developed.

As an additional feature to alleviate possible reservoir interference problems where gas wells are to be drilled on closer than one section spacing, the Board may wish to stipulate a minimum interwell distance for wells for production of gas from the same formation. The minimum interwell distance would depend on the size of the spacing unit and would be stipulated in the relevant Board spacing order. If such a stipulation were to prevent an operator from drilling and completing a well within the specified target area, the Board would be prepared to consider an alternative target area for that special case.

Oil Zones

The Board believes that the benefits of corner target areas are such that they should also be instituted for oil developments wherever possible. The Board recognizes the special problems of correlative rights with the heavy type of oil normally found in southern Alberta but believes that even in these circumstances corner target areas are reasonable for undeveloped lands. Also, the alternative of having different target areas for oil and gas spacing units would lead to serious complications in the location of exploratory wells. For these reasons, the Board is prepared to specify the corner target areas outlined in Attachment 3 to be applicable for new oil wells. The normal drilling spacing unit for an oil well is one quarter section with the target area located within the quarter section having sides 660 feet from the sides of the drilling spacing unit and parallel to them. For new oil wells drilled on normal drilling spacing units the Board will adopt a target area location in the north-east corner of the spacing unit. Thus the target areas for normal oil spacing will be L.S.D.'s 6, 8, 14 and 16.

The Board will also adopt a corner target area for oil wells drilled on one L.S.D. and two L.S.D. spacing. The new target areas will be one-quarter of a legal subdivision. In order to minimize the potential interference with irrigation operations where development is on two L.S.D. spacing, the target area for two L.S.D. spacing will be in the north-west corner of the even numbered L.S.D.'s. The target area for one L.S.D. spacing will be in the north-west corner of an L.S.D.

The Board believes that, for oil pools, some lease line drainage could take place but if this corner target area is maintained over a large area, the Board is of the view that, with the same rules applying to all owners, no significant inequities will be created. Attachment 3 shows that for one L.S.D. drilling spacing units, even with corner target areas, four wells out of the total possible wells for a section would be located near the middle of the quarter section. Thus, the impact on irrigation operations, although somewhat reduced, would still be significant. The Board sees no practical solution to this problem when one L.S.D. spacing is necessary, except as amended surface completion practices may minimize the effects.

As in the case with gas wells, a revised approach to calculating penalty factors for off-target oil wells will be needed. To alleviate possible reservoir interference problems the Board may also stipulate an appropriate minimum inter-well distance where oil wells are to be drilled on smaller than normal spacing units.

Procedure for Making the Changes

From the evidence presented at the hearing, the Board considers that corner target areas are appropriate for future development of gas pools and oil pools in southern Alberta and thus is issuing an order specifying corner target areas. In summary the spacing order will:

(a) Pertain to all lands in the Province south of Township 31 and east of the 5th Meridian;

(b) Stipulate that the normal target area for half section, quarter section, two L.S.D. and one L.S.D. spacing units is a corner target area as described more specifically on Attachments 2 and 3, depending on the size of the spacing unit;

(c) Not make any change in the spacing unit sizes now in effect;

(d) Continue the present status of existing on-target and off-target wells; and

(e) Define the procedure for calculating penalty factors for off-target wells.

Future changes to spacing, whether they are changes in target areas or in the size of spacing units, will be made through amendments to the spacing order.

The Board recognizes that changing the location of the normal target area from the center to the corner of a quarter section or spacing unit is a significant change from established practice and, particularly for oil, there may be special cases where the change would have a significant unfavourable impact. The Board also notes that many of the lands included in the decision area will not be irrigable. For these reasons the Board, after issuing its spacing order, will allow 120 days for objections pertaining to specific cases to be made by affected parties. The Board, after 120 days and as it judges appropriate, would further amend the spacing order with respect to the area affected or other matters. Subsequent changes would result only from special applications for changes in spacing which would be dealt with in the normal manner.

7.0 SURFACE COMPLETION PRACTICES

7.1 Views of Irrigation Association

The Irrigation Association stated that lowered wellheads could to some extent minimize interference problems. The Irrigation Association also stated that it was concerned about possible additional equipment which might become necessary for oil and gas operations in future years and might interfere with irrigation operations.

7.2 Views of Alberta Eastern

Alberta Eastern's comments again dealt only with shallow gas development in irrigation areas. It stated that it utilized basically two wellhead configurations, one for multi-zone production (Milk River or Medicine Hat and Second White Specks) and one for single zone production from Milk River or Medicine Hat zones. The multi-zone wellhead is larger by virtue of the mechanics of controlling multi-zone flow and is several feet in height. A gas meter installation is also required for multi-zone production. Since there is only one multi-zone well per section the gas meter installation can be placed on the quarter section line, out of the way of irrigation operations. Single zone wellheads could be reduced in height to 24 inches to allow sprinkler systems to pass over the wellhead.

Alberta Eastern also identified other possible sources of interference which may be caused by surface production facilities. In cases where a well is located in a field which is used periodically for cattle grazing a fence is required to protect the wellhead. The fence is generally 5 feet high. The size of the fence could not be altered without impairing its function. Alberta Eastern expressed a view that surface installations connected with gas gathering systems could be modified to reduce interference problems.

7.3 Views of PanCanadian

PanCanadian presented some discussion respecting possible modifications to surface equipment that could minimize the equipment's impact on irrigation operations. It said that it is not technically feasible to submerge gas wellheads because of problems associated with water and gas accumulations. Production equipment connected with new gas wells would not create an interference problem if the wells are located in the corners of quarter sections. However, PanCanadian said it could not see such a ready solution for the oil well situation since it said that target areas for oil wells could not be easily located in the corners of quarter sections. Furthermore the majority of oil wells in the subject area require pump jacks which could not be buried. In response to questioning, PanCanadian said that it had investigated certain types of alternative lifting equipment and its investigations had indicated that the tested equipment was not a feasible alternative to pump jacks. Access roads and power lines necessary for oil wells could add to the interference problem.

7.4 Views of the Board

The Board has taken the view that the most practical remedy to the situation of inter-industry interference in irrigation areas is a non-central target area, combined with revised requirements for drilling licence applications. For this reason, the Board is not prepared at this time to require any modification of surface production facilities for wells located in the corners of the quarter sections. If, for whatever reason, a new well is located other than in the corner of the quarter section, the Board may require that the installed surface facilities meet special conditions to minimize interference with irrigation operations.

8.0 OTHER CONSIDERATIONS

8.1 Views of Irrigation Association

The Irrigation Association, in addition to raising the question of notice respecting drilling permits, stated that it would be advantageous if notices of application for special spacing units could be published in the local newspaper of the area involved.

The Irrigation Association made two additional points which dealt with the petroleum industry's operation in irrigation areas. First, it suggested that if land is levelled for irrigation purposes the pipe line company should be required to lower its line, if necessary, at its own expense. Second, the Irrigation Association said that it did not believe that the content of liquid sumps from drilling operations should be pumped over good agricultural land. It suggested that the effluent from the sumps should be hauled away and disposed of in a more suitable manner.

8.2 Views of Petroleum Industry

Representatives of the petroleum industry did not comment on these matters.

8.3 Views of the Board

The Irrigation Association's suggestions regarding publication of notice cover two separate aspects of the Board's operations. First, the Board in its regulations, commits itself to publish notice of all applications which request a change in the normal spacing regulations. In the past, these notices have only appeared in the Provinces' major newspapers as the notices were intended to notify affected mineral owners. However, as a result of the recommendations contained in the examiners' report on the Merland application, the Board has decided to have notices regarding changes in spacing regulations or orders published in local newspapers where, in the opinion of the Board, the local residents would be interested in the proposed changes.

The second public notice item raised by the Irrigation Association concerns the publication of notice regarding applications for drilling licences in irrigable areas. As was discussed in Section 4, the Board has adopted the principle of providing the surface owner with reasonable opportunity to object to a well location before a drilling licence is issued.

The Board advises that it does not permit drilling fluids to be drained or disposed of on the land surrounding the surface lease.

Concerning the fencing of pipe line easements, the Board believes that it is not practical to require such fencing. The Board is satisfied that if the pipe line company exhibited some flexibility regarding the timing of construction of the pipe line and the location of the pipe line, many of the farmer's complaints could be eliminated. Moreover, the Board believes that the corner location of well target areas will materially reduce this problem.

The final matter brought to the Board's attention was the issue of lowering pipe lines for land levelling purposes. The Board is of the view that the appropriate time to make provision for pipe line lowering, necessitated by planned future land levelling, is at the time that the initial agreement between the pipe line company and the landowner is made. If irrigation is planned, the landowner might negotiate to have the pipe deeply buried or have a clause included in the agreement which would obligate the pipe line company to lower its pipe line at the time that irrrigation facilities are installed. The Board does not believe that there should be a regulation requiring the pipe line owner to lower, at his own cost, any pipe line that interferes with a potential future irrigation project.

9.0 DECISION

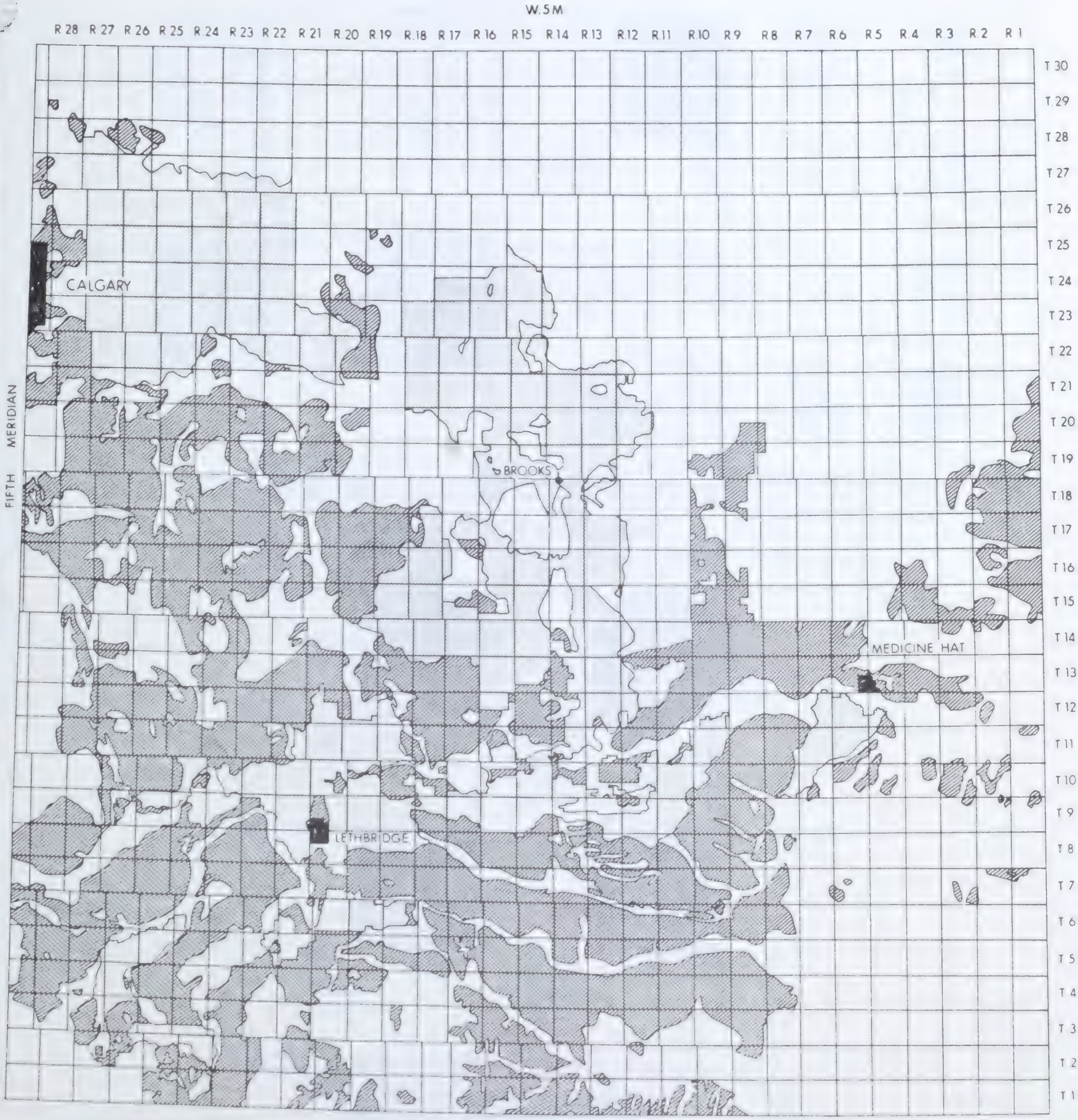
The Board will establish corner target areas for new gas and oil wells in that part of Alberta south of Township 31 and east of the 5th Meridian. The Board will make provision for exemption in particular cases.

ENERGY RESOURCES CONSERVATION BOARD

D R Craig

D. R. Craig
Vice Chairman

Dated at Calgary, Alberta,
May 24, 1974.

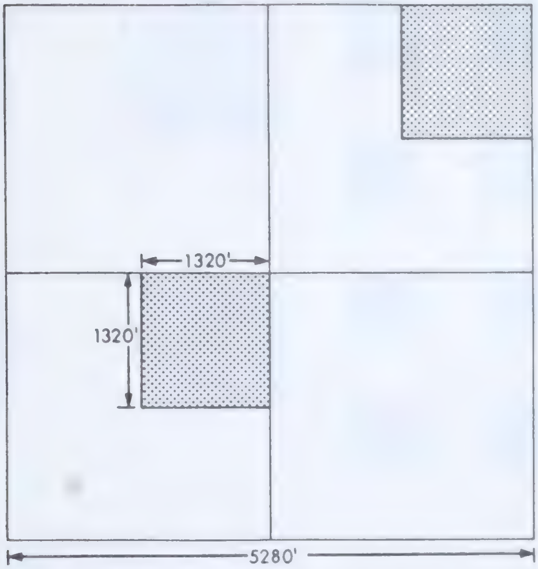


ATTACHMENT 1: POTENTIAL AND EXISTING IRRIGATION AREAS

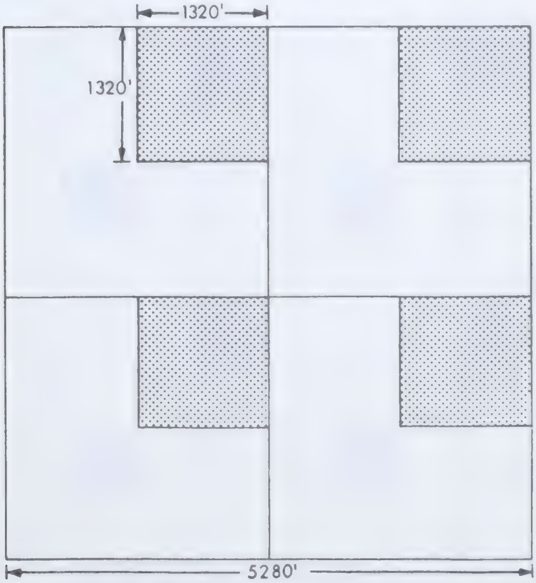
☐ EXISTING

▨ POTENTIAL

ENERGY RESOURCES CONSERVATION BOARD
CALGARY ALBERTA



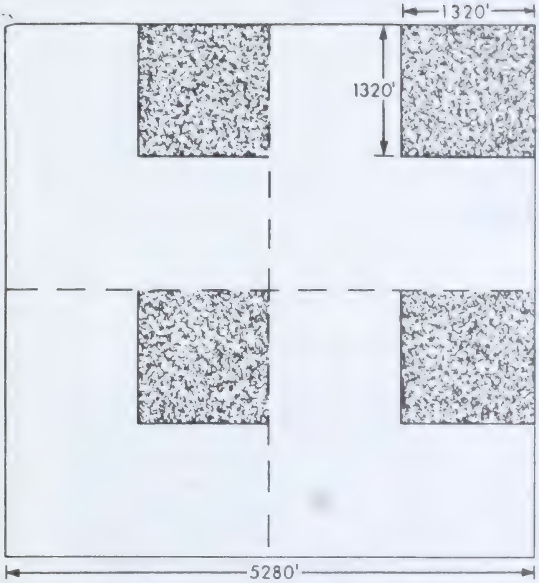
A. TARGET AREA FOR 1/2 SECTION DRILLING SPACING UNIT



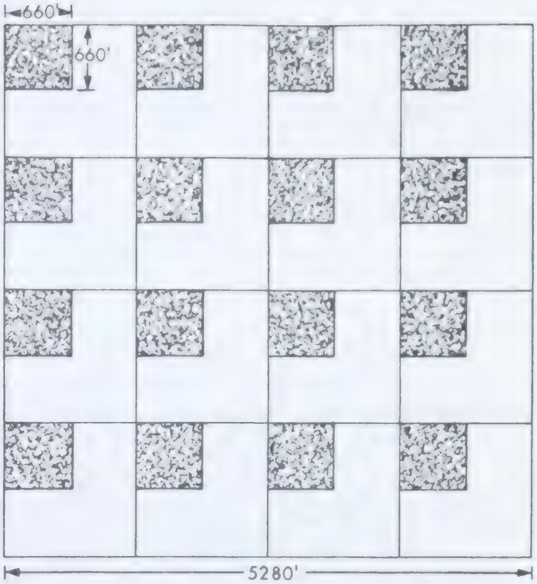
B. TARGET AREA FOR 1/4 SECTION DRILLING SPACING UNIT

ATTACHMENT 2: NEW TARGET AREAS FOR GAS WELLS IN IRRIGABLE AREAS

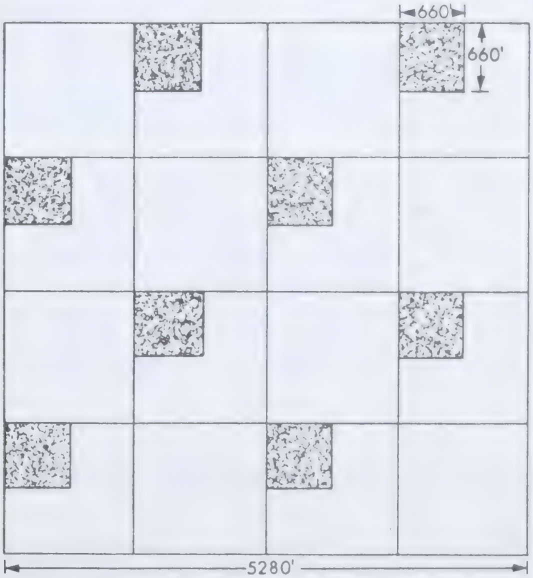
ENERGY RESOURCES CONSERVATION BOARD
CALGARY, ALBERTA



A. NORMAL OIL DRILLING SPACING UNITS
CORNER TARGET AREAS



B. 1 LSD OIL DRILLING SPACING UNITS
CORNER TARGET AREAS



C. 2 LSD OIL DRILLING SPACING UNITS
CORNER TARGET AREAS

ATTACHMENT 3: NEW TARGET AREAS FOR OIL WELLS IN IRRIGABLE AREAS

ENERGY RESOURCES CONSERVATIO
CALGARY, ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

Decision No. 74-6
Applications No. 7282 & No. 7283

WELL SPACING
ALDERSON FIELD

1. THE APPLICATION AND HEARING

PanCanadian Petroleum Limited applied, pursuant to the provisions of the Oil and Gas Conservation Regulations, for the establishment of drilling spacing units of one-quarter section for the production of gas from the Milk River Formation in 40 sections of land in the Alderson Field. The lands are shown on Attachment 1. The target area proposed was that part of the quarter section that would be the target area in accordance with Section 4.020, subsection (1) of the Oil and Gas Conservation Regulations if the quarter section were a drilling spacing unit for an oil well.

The applications were initially reviewed by the Board as to reservoir and conservation aspects and on that basis the Board considered the applications to represent a sound proposal. For this reason, the Board published notice of the subject applications and indicated that unless objections were filed with respect to the applications, it would grant them.

Following publication of notice the Board received objections to the applications from a number of interested parties. These parties objected on the basis of the impact the granting of the applications would have on surface operations. Upon receipt of the objections, and after it became apparent that these objections would not be withdrawn, the Board heard the applications in Brooks, Alberta on March 21, 1974 with D. R. Craig, P. Eng., V. Millard, and G. J. DeSorcy, P. Eng. sitting.

2. APPEARANCES

The following appeared at the hearing:

	Represented by
PanCanadian Petroleums Limited (PanCanadian)*	W. S. Bishai, P. Eng. T. M. Lawrence, P. Eng.
The Eastern Irrigation District Landholders Association (Irrigation Association)*	Don Alberts Steve Merkl
Board Staff	R. G. Evans, P. Eng. A. L. McLarty I. F. Taylor, E.I.T.

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*Abbreviations in brackets are used throughout report.

3. DEFINITION OF ISSUES

The reservoir aspects of granting the application were not raised by any of the interveners and consequently were not issues considered at the hearing. The interveners were concerned with the impact the target areas proposed in the applications would have on surface operations and this is the only relevant issue. The Board considers that the one-quarter section spacing units proposed by the applicant are appropriate with respect to size.

4. THE QUESTION OF TARGET AREAS

4.1 Views of the Applicant

PanCanadian stated that at the time it had applied for the central target areas, such target areas were commonly used by the industry to develop shallow gas zones. In response to questioning, PanCanadian stated that it had not altered its proposed central target areas to corner target areas mainly because of the serious delay that would result in its extensive summer drilling program if it amended its applications.

4.2 Views of the Interveners

The Irrigation Association stated that if action were to be taken to alleviate inter-industry interference problems this action should be initiated for the PanCanadian applications.

4.3 Views of the Board

The Board notes that at the time PanCanadian submitted its applications central target areas were generally the accepted rule for one-quarter section spacing. Since that time the Board has been made aware of the problems associated with central target areas and has issued Decision 74-5 which specifies a corner target area for gas wells on quarter section spacing. Since the target areas proposed by PanCanadian differ from the now stipulated corner target areas and because in the Board's view PanCanadian did not give evidence supporting the need for central target areas, the Board is not prepared to approve the central target areas proposed in the PanCanadian applications.

The Board notes that PanCanadian has already drilled certain wells within the area of application on the basis of central target areas. Since these wells were drilled before Decision 74-5 was issued the Board considers that these wells should be deemed to be on target and should not be subject to penalty factors.

5. DECISION

(1) The Board grants Application No. 7282 and No. 7283 with respect to the proposed one-quarter section spacing unit size.

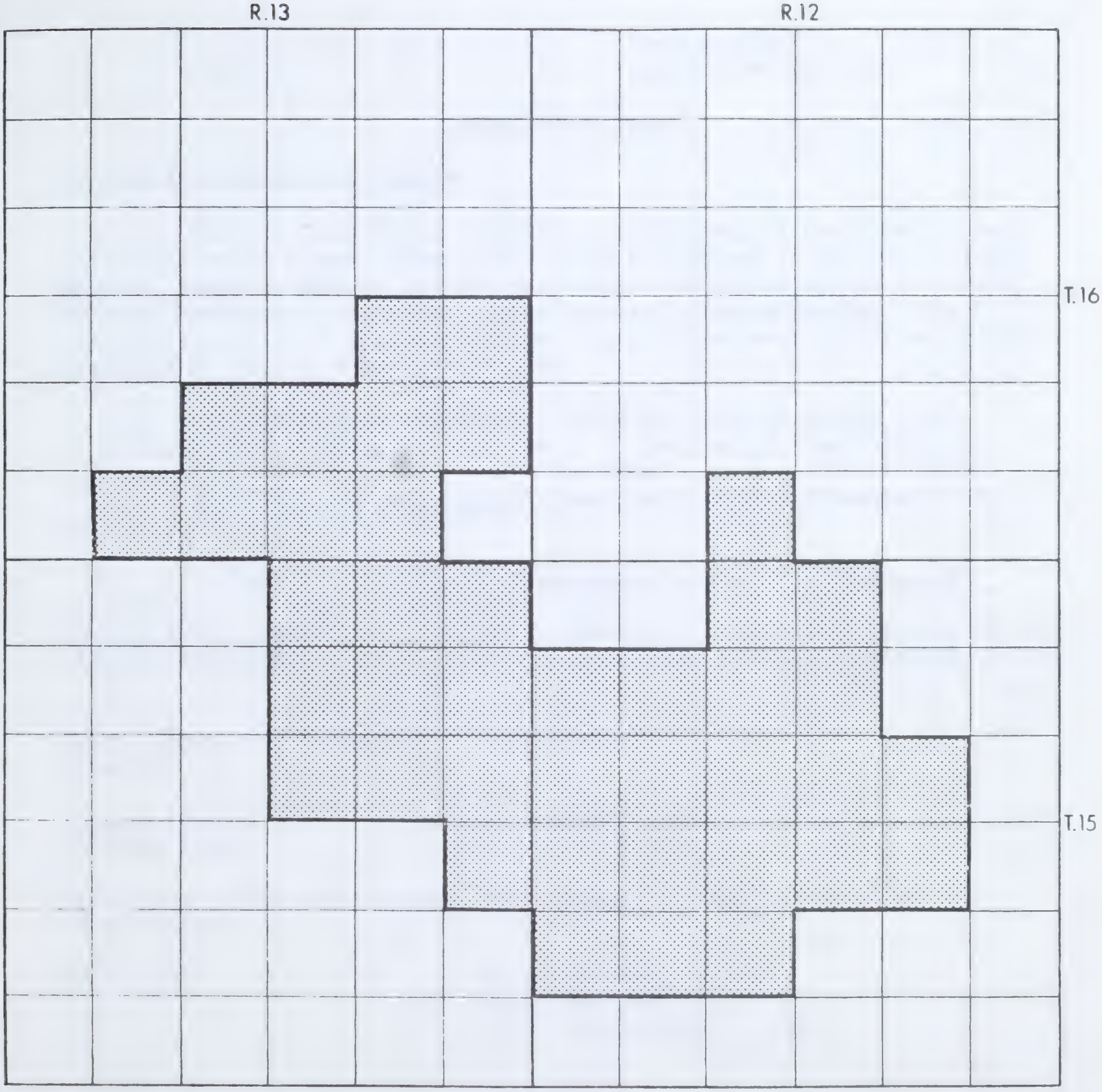
(2) The Board denies the parts of Application No. 7282 and No. 7283 with respect to a central target area.

ENERGY RESOURCES CONSERVATION BOARD

DRCraig

D. R. Craig
Vice Chairman

DATED at Calgary, Alberta
May 24, 1974



ATTACHMENT 1: AREA OF APPLICATION

Office Services
ERCA-1 CMAR-1 HEA-1 OGAR-1 PLAR-1
IL-14 ILC-14 ILHE-14 ILOG-15 ILPL-14
ID-14 IDC-14 IDHE-14 IDOG-14 IDPL-14
DPPL-28 OAR-1 O&A-1

ENERGY RESOURCES CONSERVATION BOARD

Decision 74-7
Application No. 7775

JASPER POWER PLANT

1. THE APPLICATION AND HEARING

Alberta Power Limited applied for approval of the construction and operation of a power plant which would be located in Section 2, Township 46, Range 1, West of the 6th Meridian and which is within the Jasper National Park just north of the Trans Mountain pumping station. The application was for a plant to replace the previous power plant which was destroyed by fire in February of 1974.

The application was heard on June 19, 1974 at Jasper with V. Millard, J. I. Strong, P. Eng. and G. J. DeSorcy, P. Eng. sitting.

The following table lists those parties which appeared at the hearing:

Name	Represented by	Witnesses
Alberta Power Limited (Alberta Power)(1)	B. V. Massie, Q.C.	A. L. Boykiw, P. Eng. J. Winkelaar, P. Eng. K. Provost, P. Eng.
Jasper Chamber of Commerce (Chamber)	J. A. Bryan	
Calgary Power Ltd. (Calgary Power)	J. Hoover, P. Eng. W. Janke, P. Eng.	
Department of the Environment (Department)	S. L. Dobko, P. Eng.	
Board Staff	C. J. Goodman, P. Eng. N. A. Macleod, Q.C. K. I. Montgomery, P. Eng.	

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(1) Abbreviation used through the decision

The capacity of the proposed plant would be 8400 kilowatts, consisting of two 1200 kilowatt and two 3000 kilowatt internal combustion engine driven generators, with provisions made for the installation of additional capacity at a later date. All of the proposed units would burn natural gas, which would be supplied from the existing gas line serving the Town of Jasper, and propane would be stored at the site as standby fuel. Waste gas from the proposed power plant would be exhausted to the atmosphere through a stack of sufficient height to meet the required standards of the Department of the Environment regarding oxides of nitrogen.

The application also contained the applicant's assessment of the alternative means of supplying electric energy to the town. One alternative would be to supply energy via a 72 kV (thousand volt) transmission line which would involve purchasing electric energy from Calgary Power Ltd. at the park boundary and transmitting this energy to the town using a new 72 kV transmission line which the applicant would construct on the west side of the Athabasca River. A second alternative would be to build the above-mentioned transmission line and to also construct a peaking and standby power plant, consisting of two 600 kilowatt gas burning internal combustion engine driven generators, at the location of the power plant presently applied for.

At the hearing the applicant requested an early decision in order to expedite plans for the supply of electric energy to Jasper. The Board appreciates the concern of the applicant and in view of these special circumstances has decided to issue a brief decision report. The Board, however, has carefully considered all of the evidence submitted at the hearing and has carried out its own analyses to the extent necessary.

The Board believes that consideration of the application involves assessing the alternative means of supplying electric energy to Jasper under the following issues:

(a) Economics

(b) Environmental Impact

(c) Reliability

(d) Energy Resource

2. ECONOMICS

The applicant's assessment of the relative economics of the alternatives indicated that the transmission line alternatives offered a marginal economic advantage over the proposed power plant. It was Alberta Power's view that other factors such as environmental considerations outweighed the cost advantage of the transmission line and therefore submitted that the proposed power plant was the most suitable alternative.

The main concern expressed by the Chamber at the hearing was with regard to providing electric energy at the lowest cost to the consumers in the Town of Jasper.

The analysis carried out by the Board was based on the 1974 capital and operating cost estimates supplied by the applicant for each case and the Board considered these to be reasonable. The Board used a gas price forecast in its analysis which was generally higher than any of the price schedules presented by the applicant since the Board believes that its forecast of gas prices more closely reflects the trend of increasing commodity values of this fuel. The Board's economic analysis indicated that each of the alternatives involving a transmission line would be somewhat more economic than the proposed power plant and could offer a net present worth saving of about 2 million dollars over the period from 1975 to 1992 when considered on a discounted cash flow basis.

3. ENVIRONMENTAL IMPACT

The applicant considered that the transmission line would have a greater overall environmental impact than the proposed power plant and pointed out that it did not receive any assurances from Parks Canada that the route studied for a transmission line would be acceptable. Alberta Power expected that at least one mile of the route examined would have to be buried and this could affect the capacity and reliability of the transmission line alternatives. The applicant maintained that since an inconspicuous source of energy for Jasper already exists, in the form of an underground gas line, the construction of a power plant at Jasper would be the most desirable alternative.

Both the proposed power plant and the transmission line alternatives involve two main types of environmental impact: their effect on the natural environment and their aesthetic impact on the scenery within the park. The power plant would likely have a lesser effect on the natural flora since it would require only a small amount of clearing in a semi-developed area adjacent to the Trans Mountain pumping station, whereas a transmission line would require removing considerably more trees in order to establish an adequate right of way. In regard to gaseous pollutants the Board does not expect the emissions of oxides of nitrogen from the power plant to cause any environmental damage since the applicant has agreed to meet the required ground level concentration standards established by the Department of the Environment.

With respect to the visual impacts of the proposed power plant and the transmission line alternatives, the Board believes that the power plant would have a lesser impact than a transmission line since the power plant stack would likely only be visible within the immediate vicinity of the plant, mainly from Highway No. 16, whereas the linear nature of the transmission line would take it through a larger portion of the park but it would not for the most part be visible from Highway No. 16.

Having regard for the recreational nature of the general area, the Board is satisfied that in relative terms the power plant would have the least environmental impact of the alternatives examined.

4. RELIABILITY

In assessing the relative reliability of the three alternatives Alberta Power indicated that a quantitative comparison was not possible. However, the applicant commented that during the operation of the previous power plant at Jasper there had been no situation in which there was a complete power failure apart from the recent fire. On this basis Alberta Power felt that the proposed local generating plant would be the more reliable of the alternatives examined.

In comparing the reliability of electric service that the proposed power plant or the transmission line alternatives could likely achieve, the Board considered the extent and duration of potential outages which could occur in each case. The Board is satisfied that in the long term the proposed power plant would provide a marginally better degree of reliability than the other alternatives. The Board also believes that the proposed power plant would offer some advantages, with respect to the reliability of electric service to Jasper in the short term, since it could be in service much sooner than a transmission line.

The Board recognizes that the Town of Jasper must be assured of reliable electric service in the interim period during which a permanent means of providing electric energy to the town is being built. Since the applicant has indicated that all of the units for the proposed power plant may not be in service in time to meet the peak load requirements during the coming winter, and since it is clear that a transmission line could not be in service during the coming winter, the Board expects the applicant to take the necessary steps to provide adequate temporary generating capacity capable of meeting Jasper's peak load requirements until permanent facilities are installed.

5. ENERGY RESOURCE

The applicant proposed to use natural gas as the primary fuel for the power plant and based on the projected electric energy requirements of the town, Alberta Power estimated that about 6.9 billion cubic feet of gas would be consumed in the generation of the electric energy required over the period from 1975 to 1992.

The Board's recommendation, as expressed in ERCB Report 73-C and which has been endorsed by the Provincial Government, is that coal is the most suitable resource for the generation of base load electric energy in Alberta. In this regard the construction of a transmission line to supply Jasper with electric energy from the coal-fired power plants of the provincial system would be more consistent with this recommendation than the proposed power plant which would burn natural gas. The Board recognizes, however, that this is a unique situation in that there is an existing gas line to the town, that a transmission line within a national park may not be desirable, and that the proposed power plant would consume a relatively small amount of natural gas. In addition the Board notes that the existing gas line provides a readily available source of energy and that the proposed plant would only be replacing the previous plant which also burned gas. The Board therefore does not consider the use of natural gas to be a critical factor in this particular case.

6. DECISION

The Board considers that the economic and resource use advantages of the transmission line alternative must be balanced against the environmental and reliability disadvantages. An important element in the weighing of these factors is the later in-service date of the transmission line should this alternative be adopted. Because it is possible that additional time may be required to obtain the necessary approvals from Parks Canada, to conduct environmental studies, to secure the required construction materials and to allow for the necessary winter construction, the Board recognizes that a transmission line might not be in service until 1976.

The Board believes that a delay in the completion date of a transmission line could affect both the economic and reliability factors involved in the ultimate choice of an alternative. Because of rapidly escalating costs of transmission line materials any delay in construction would result in higher costs. In addition the applicant would be required to obtain generating equipment for the temporary Jasper plant during the interim period which could result in expenditures either through the rental or purchase of generating equipment. Furthermore, operating costs during this interim period would be significantly greater due to the price of diesel fuel required for the temporary plant compared to the natural gas used by the proposed permanent facilities. Thus the 2 million dollar economic advantage associated with a transmission line would be reduced by a delay in the completion of a transmission line but not to the extent where the economic advantages of a line would be completely eliminated.

Another aspect of a delayed completion date is its impact on reliability. While this is difficult to assess, the Board believes that temporary generating facilities may, due to their greater exposure to the elements, have somewhat less reliability than the proposed permanent facilities

In summary, the Board believes that the transmission line alternatives have an economic advantage over the proposed power plant but would be slightly less reliable and would have a greater impact on the environment. The Board considers the environmental issue to be particularly important in this case since it is in a national park and it believes that the environment should not be disturbed unless there are compelling reasons. In this instance the power plant offers an alternative which is somewhat more expensive than the transmission line but the Board does not believe that the magnitude of the additional cost of this alternative is significantly compelling to warrant construction of the transmission line. For these reasons the Board is satisfied that, at the present time, the proposed power plant is the most suitable means of providing electric energy to the Town of Jasper. The Board therefore will grant the application for the initial stage of the power plant.

The Board recognizes that in the future the rapidly escalating price of gas may cause the applicant to reconsider the relative merits of a transmission line and could lead to an application to construct a transmission line to supply base load energy to Jasper with the proposed power plant serving as a peak or standby plant. In the event of such an application, the Board would consider it on the basis of the facts presented by all parties at that time.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
July 16, 1974

ENERGY RESOURCES CONSERVATION BOARD

Decision 74-8
Application No. 6563

EXEMPTION FROM SULPHUR RECOVERY GUIDELINES OKOTOKS GAS PROCESSING PLANT

Texasgulf, Inc. (hereinafter called "Texasgulf") in an application dated August 14, 1972, applied to the Energy Resources Conservation Board to exempt the Okotoks Gas Processing Plant, located in the South-west quarter of Section 27, Township 20, Range 29, West of the 4th Meridian, from the sulphur recovery guidelines provided in Board Informational Letter No. IL 71-29. The Okotoks Gas Plant is currently permitted to process a maximum sulphur inlet rate of 452 long tons per day and required to recover, as elemental sulphur, a minimum of 93.0 per cent of the sulphur contained in the gas delivered to the plant. Informational Letter No. IL 71-29 requires that a plant with an inlet rate of between 400 and 1,000 long tons per day of sulphur, processing a favourable quality acid gas, recover a minimum of 96 to 98 per cent of the sulphur contained in the gas delivered to the plant. The guidelines indicate that a recovery level of 96 per cent would be required for the Okotoks Plant.

On March 27, 1973, the Board published notice of the application. The notice stated that, unless objection was filed on or before April 19, 1973, the Board might grant the application in part by setting the sulphur recovery efficiency at 94.0 per cent. No objection to the application was received. The Board, therefore, decided that a public hearing of the application was not necessary. However, inadvertent delays and rapidly changing product prices led to several meetings with the applicant concerning the economics of an additional stage of sulphur recovery. These discussions resulted in three additional submissions from the applicant dated December 7, 1973, January 21, 1974 and May 23, 1974. The Board has prepared this report to document the Board's decision respecting the application.

THE APPLICATION

Texasgulf applied for exemption from the recovery levels set out in the guidelines and requested that the Board continue to apply the recovery levels presently being adhered to in the operations of the Okotoks plant. Texasgulf's application for exemption was based on its claim respecting the adverse economics of adding additional recovery equipment to the existing plant and on the lack of damage to the environment as a result of the present method of operation.

Texasgulf stated that the existing plant is capable of processing 34.6 million cubic feet per day (MMcfd) of sour gas and producing 16.2 MMcfd of sales gas, 415 long tons per day (LTD) of sulphur, and 95.5 barrels per day of condensate and sweet aromatics. The gas is produced from wells in the Okotoks Unit and four non-unit wells.

The gas processed averages approximately 34 per cent hydrogen sulphide and 11 per cent carbon dioxide. Field and plant fuel requirements amount to approximately ten per cent of the inlet gas so that the total plant shrinkage and the present low selling price for sulphur make the economics of the present operation marginal. It stated that any requirement of a large cash outflow could precipitate a decision to close the facilities.

The applicant also stated that the sulphur conversion plant consists of two trains, each capable of processing one-half of the acid gas. Each train has two converter beds and a wash tower-type final condenser. The combined tail gas streams pass through a coaleser just ahead of the incinerator. Stack surveys conducted by Texasgulf during 1972 indicated recoveries for the plant ranging from 94.0 to 95.1 per cent. The average recovery indicated by all efficiency determinations submitted by Texasgulf is 94.3 per cent.

The applicant stated that with the close plant control and periodic renewal of catalyst the existing sulphur recovery can be maintained but that a third stage of catalytic conversion would be required to increase the sulphur recovery to 96 per cent. The capital cost of the third stage was estimated to be $600,000.

In light of rapidly changing conditions and at the request of the Board, Texasgulf submitted in May 1974, updated economic data which indicated that no cash return is expected during the remaining project life even without installing the third converter. Its revised data indicated an expected cash loss for the period 1974 to 1985 of approximately $4,725,000. Requiring the additional third stage would increase the cash loss by approximately $600,000 to $5,325,000.

For the purpose of this evaluation, Texasgulf also used a new production schedule for the Okotoks field which reflects a more rapid decline in productivity than previously estimated and, as a result of the existing contract, assumed a residue gas price of 14 cents per thousand cubic feet for the period 1974 to 1977 and a price escalating from 50 cents to 84 cents per thousand cubic feet for the period from 1978 to 1985. A sulphur price of $12 per long ton was used throughout the period while the condensate was increased from $5.18 per barrel to $6.68 per barrel. The price of the aromatic condensate was initially $7.11 per barrel in 1974 and was increased to $8.11 per barrel by 1985. It assumed sulphur sales of 50 per cent of production in 1974 increasing to 60 per cent by 1985. Although the plant would still be in operation beyond 1985, this was the date to which the economic evaluation was carried out.

Texasgulf also presented evidence respecting its claim that there has been no damage to the environment due to emission of unrecovered sulphur to the atmosphere as a result of the present method of operation. It stated that the plant has been operated for approximately 13 years and has not been responsible for any pollution damage in the Okotoks area. To verify this claim, it submitted the results of three false colour infrared aerial photographic surveys carried out in 1969, 1970 and 1971; a soil survey carried out in August, 1970; exposure cylinder monitoring for 1971 and part of 1972; and the results of three months of continuous air quality monitoring carried out in late 1971 and early 1972. None of these surveys indicated environmental damage resulting from incinerator stack emissions or sulphur dioxide concentrations or sulphation levels in excess of the Provincial standards.

VIEWS OF THE BOARD

As stated in previous decisions concerning similar applications the Board believes that, even though by present standards, the environmental aspects of a plant operation might be satisfactory, maximum practical sulphur recovery should be achieved both in the interests of conservation of a natural resource and to minimize sulphur dioxide emissions with regard to the potential for adverse environmental effects on a broad scale. The Board believes that, in general, the sulphur recovery specified in the guidelines should apply providing that it would give a discounted rate of return before income tax in the range seven to ten per cent on the total undepreciated investment attributed to the total sulphur recovery facilities evaluated as of January 1, 1975. The Board stated further, in Decision 72-8 respecting exemption of the Harmattan Leduc Gas Processing Plant from the sulphur recovery guidelines, that it may look at the overall economics of a gas processing operation including costs and revenue related to the recovery of residue gas and liquids prior to ruling on an application.

In considering the present application the Board first reviewed the recovery capability of the existing facilities. Information available to the Board indicates that the Okotoks plant should be capable of a theoretical maximum recovery of approximately 95 per cent and of maintaining a practical operating level of approximately 94 per cent. This is confirmed by Texasgulf's data which indicates the plant to be presently operating at an average recovery of 94.3 per cent. The Board concurs with the position taken by the applicant that addition of a third stage would be necessary to increase the minimum operating recovery to 96 per cent. The Board estimates that addition of the third stage would cost a minimum of $600,000 and would increase annual operating costs by approximately $48,000.

Since sulphur cannot truly be considered a by-product of the subject plant operation (revenue from sulphur sales represents over 40 per cent of total revenue), the Board is of the view that overall economics should form the basis of the decision regarding the application. The Board evaluated the economics of the plant for the period 1975 to 1985 inclusive, in the same manner as outlined in other decision reports. No unrecovered past investment for the existing gas processing and sulphur plant was carried forward to January 1, 1975. Utilizing a $12 per long ton sulphur price and the applicant's price schedule for pentanes plus and aromatic condensate, the Board's evaluation indicated negative cash flows and no payout over the 11 year period, either for sulphur sales fractions used by the applicant or for 100 per cent sulphur sales. While the Board believes the applicants price schedule for pentanes plus and aromatic condensate to be too conservative, it agrees that an upward adjustment would not change the overall conclusion.

As another test of the Okotoks plant operation, the Board reviewed the revised overall field and plant economics submitted by the applicant, in May 1974, making certain adjustments. This evaluation indicated a cumulative net loss before taxes for the period 1975 to 1985 of $3,660,000. The Board concluded that installation of a third stage sulphur recovery plant could not be justified on economic grounds.

Respecting a related matter, a recent review by Board staff indicated the incinerator stack at the plant to be deficient in regard to the calculated ground level concentration standard. This situation arose since the stack design was approved some time ago when stack design calculation methods and ambient air quality standards were less stringent. Calculations by Board staff using the Pasquill method indicate concentrations of sulphur dioxide up to 0.55 parts per million on hills 0.75 to 1.5 miles north of the plant. As a result of this finding, Texasgulf was required to carry out 3½ months of continuous monitoring in the critical area. This monitoring did not detect excessive sulphur dioxide concentrations. In view of the acceptable monitoring results, the absence of complaints from local residents, and the generally satisfactory conditions of the environment in the Okotoks area, the Board believes that major modifications need not be made at this time to meet the calculation standard but that an increase in monitoring requirements would be desirable. Approval No. 1398 now requires two months of continuous monitoring per year and the use of seven exposure cylinder stations. The Board notes that gas plant standards of the Department of the Environment would require an increase in monitoring at the subject plant to 12 months of continuous monitoring per year and 20 exposure cylinder stations. In the Board's view the increased monitoring should satisfactorily resolve the problem of the apparent stack deficiency. If unacceptable sulphur dioxide concentrations are indicated by monitoring in the future, the Board would reconsider the adequacy of the existing stack and the need for plant modifications.

The Oil and Gas Conservation Act, Section 38, subsection (1), provides that the Board shall refer an application under subsection (b) to the Minister of the Environment for approval of the application as it affects matters of the environment.

The Board, in compliance with the above, has referred the application to the Minister of the Environment for approval and he has given approval respecting this application. Accordingly, his approval has been incorporated as Appendix B to the Board's proposed draft Approval set out in Appendix A, and the Board has made its Approval subject to the same conditions imposed by the Minister of the Environment when the Minister gave approval.

DECISION

The Board grants, in part, the application by Texasgulf for exemption of the Okotoks plant from the sulphur recovery efficiency guidelines set out in Board Informational Letter No. IL 71-29. The Board requires that the sulphur recovery efficiency be increased from 93.0 to 94.0 per cent to correspond to actual plant capability, and that the ambient air quality monitoring be increased as described herein. Amendment of Approval No. 1398 is being issued concurrently with this decision.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Govier
Chairman

Dated at Calgary, Alberta
July 12, 1974

APPENDIX A

THE PROVINCE OF ALBERTA

THE OIL AND GAS CONSERVATION ACT

ENERGY RESOURCES CONSERVATION BOARD

IN THE MATTER of a scheme of Texasgulf Inc. for the processing of gas produced in the Okotoks Field

AMENDMENT OF APPROVAL NO. 1398C

(Amending Approval No. 1398)

WHEREAS the Energy Resources Conservation Board is prepared to grant, in part, an application by Texasgulf Inc. for amendment of Approval No. 1398, subject to the conditions herein contained, and the Minister of the Environment has given his approval, hereto attached, insofar as the application affects matters of the environment.

THEREFORE, the Energy Resources Conservation Board, pursuant to The Oil and Gas Conservation Act, being chapter 267 of the Revised Statutes of Alberta, 1970, hereby orders as follows:

1. Board Approval No. 1398 is amended.

2. Clause 1 is amended by adding the word "and" at the end of subclause (b) and adding the following subclause after subclause (b):

   (c) an application by the Operator to the Board dated August 14, 1972,

3. Clause 4, subclause (1), paragraph (c) is amended by striking out the numeral "93" and by substituting the numeral "94".

4. Clause 5, subclause (3) is amended by

   (a) striking out the numeral "1404" and substituting the numeral "9.040", and

   (b) adding after the word "regulations" the words "or other standards the Board or the Department of the Environment may specify".

5. Clause 9 is amended by striking out the word "two" and substituting the word "four".

6. Clause 10 is amended

(a) as to subclause (1) by striking out the word "seven" and substituting the word "twenty".

(b) as to subclause (2) by striking out the words "one month in both the summer and winter seasons" and substituting the words "twelve months".

7. Clauses 10 and 11 are amended by striking out the words "Division of Environmental Health of the Department of Health" and the words "Department of Health" wherever they occur and by substituting the words "Department of the Environment".

8. Clause 16 is struck out and the following is substituted:

16. This order, insofar as it pertains to matters of the environment, is subject to the approval of the Minister of the Environment No. 74-93 ERCB hereto attached as Appendix A and No. 74-159 ERCB hereto attached as Appendix B, and to the terms and conditions therein contained.

9. The following clause is added after clause 16:

17. The operator shall advise the Board as soon as possible prior to commencement of the date of each plant turnaround.

10. Table 1 is struck out and Table 1, hereto attached, is substituted.

11. Appendix B hereto attached is added to the approval.

MADE at the City of Calgary, in the Province of Alberta, this 1st day of October, 1974.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

TABLE 1 TO APPROVAL NO. 1398

FUEL RATES FOR FLARING SOUR GAS

For all periods of emergency flaring, the maximum calculated downwind ground level concentration of sulpher dioxide must not exceed 0.20 parts per million. For a 100-foot high flare stack the following fuel gas schedule should be followed to maintain 0.20 parts per million as a calculated maximum downwind concentration assuming the heating value of residue gas as 1000 Btu's per cubic foot.

Cubic Feet Per Second Hydrogen Sulphide	Long Tons Sulphur Per Day	Cubic Feet Per Second Fuel Gas	Million Cubic Feet Per Day Fuel Gas
1.0	3.26	5.2	0.449
4.0	13.0	88.0	7.60
10.0	32.6	180.0	15.55
30.0	97.8	350.0	30.24
40.0	130.4	440.0	38.02
60.0	195.5	550.0	47.52
100.0	325.9	700.0	60.48
200.0	651.8	980.0	84.67

NOTE: This table is intended only as a guideline for emergency flaring and in order for individual gas plants to be assured of compliance with the ambient standards, each operator should compile a more detailed schedule based on specific plant flaring data and local topography.

APPENDIX A TO APPROVAL NO. 1398

Department of the Environment

MINISTERIAL APPROVAL

No. 74 - 93 ERCB

Edmonton, Alberta
June 19, 1974

Pursuant to section 38 of The Oil and Gas Conservation Act, I, William J. Yurko, Minister of the Environment, hereby approve Application No. 7722, dated April 10, 1974, from Texasgulf Inc. to the Energy Resources Conservation Board, as its schedule of compliance to achieve Class B emission standards as prescribed in the Gas Processing Plants Waste Water Management Standards and in reference to the letter dated December 12, 1974, from the Department of the Environment, in the matter of a scheme for the treatment of process water and produced water at the Okotoks gas processing plant, insofar as it affects matters of the environment, such application to be granted by the Board's Amendment of Approval No. 1398B, The Clean Water Act Licence No. 74-WL-054 dated June 6, 1974 and The Clean Water Act Permit No. 74-WP-046 dated June 6, 1974, copies of which are attached.

Texasgulf Inc. shall comply with The Clean Water Act Permit No. 74-WP-046, The Clean Water Act Licence No. 74-WL-054, or any subsequent amendments thereof, issued by the Department of the Environment.

W. J. Yurko
MINISTER OF THE ENVIRONMENT

APPENDIX B TO APPROVAL NO. 1398

Department of the Environment

MINISTERIAL APPROVAL

No. 74 - 159 ERCB

Edmonton, Alberta
September 16, 1974

Pursuant to section 38 of The Oil and Gas Conservation Act, I, William J. Yurko, Minister of the Environment, hereby approve, in part, Application No. 6563, dated August 14, 1972, from Texasgulf Inc. to the Energy Resources Conservation Board, in the matter of a scheme for the processing of gas produced in the Okotoks Field, insofar as it affects matters of the environment, such application to be granted by the Board's Amendment of Approval No. 1398C and The Clean Air Act Licence No. 74-AL-091 dated August 8, 1974, copies of which are attached.

Texasgulf Inc. shall comply with The Clean Air Act Licence No. 74-AL-091, The Clean Water Act Permit No. 74-WP-046 dated June 6, 1974, The Clean Water Act Licence No. 74-WL-054 dated June 6, 1974, or any subsequent amendments thereof, issued by the Department of the Environment.

MINISTER OF THE ENVIRONMENT

ENERGY RESOURCES CONSERVATION BOARD

Decision 74-9
Application No. 7650

APPLICATION FOR RELOCATING A PORTION OF APPROVED RIGHT OF WAY FOR 240 kV TRANSMISSION LINE IN THE MILL WOODS SUBDIVISION - EDMONTON

1. THE APPLICATION AND HEARING

The City of Edmonton applied under section 40 of The Energy Resources Conservation Act and/or section 13 of The Hydro and Electric Energy Act for

(a) the dismantling of that portion of Calgary Power transmission line CP 904L located in the diagonal portion of the existing right of way from "W" to "X" as shown in Appendix A,

(b) the revocation of the Board's Permit and Licence No. CP 74-1 authorizing Calgary Power to construct a transmission line along that portion of the right of way from "W" to "Y" as shown in Appendix A, and

(c) the granting of a permit and an order authorizing and requiring Calgary Power to construct a portion of its transmission line along route "W-G-F-Y" as shown in Appendix A.

An intervention was filed by Saucier, Jones, Black, Gain, Stratton and Laycraft on behalf of Calgary Power Ltd. for the purpose of presenting Calgary Power's position on the application.

The application was heard by the Board at Edmonton on April 22, 1974, with V. Millard, J. I. Strong, P. Eng. and N. Berkowitz sitting. On the motion of Calgary Power Ltd. concurred in by the City of Edmonton, the Board adjourned the hearing sine die pending the result of agreement negotiations between Calgary Power Ltd. and the City of Edmonton. The parties have subsequently filed with the Board a copy of an agreement, and the Board, as a result, did not find it necessary to reconvene the hearing and it was as a result closed.

2. APPEARANCES

The following appeared at the hearing:

	Represented by	Witnesses
City of Edmonton	H. F. Wilson	P. Bargen P. Ellwood M. Welykochy W. Thoman R. McClary, P. Eng. V. Kondrosky, P. Eng.
Calgary Power Ltd.	D. O. Sabey, Q.C. H. M. Kay	
Board Staff	C. J. Goodman, P. Eng. N. A. Macleod, Q.C. J. N. G. Yu, P. Eng.	

3. THE BACKGROUND AND THE ISSUE OF THE APPLICATION

The subject application is the result of the Board's decision rendered on Application No. 7103 made by Calgary Power Ltd. for a 240 kV double circuit steel towered transmission line from the Sundance power plant to East Edmonton. The background and issues of that application and how the Board dealt with it are presented in ERCB Report 74-B entitled "In the Matter of An Application of Calgary Power Ltd. Respecting a Transmission Line from the Sundance Power Plant to East Edmonton" dated January 1974.

The Board believes that the issue of the subject application is centered on the relocation of a portion of the approved right of way from "WY" (see Appendix A) in the middle of the Mill Woods Subdivision to a new right of way along "WGFY" in the west, south and east periphery of the same subdivision in the south-east sector of the City of Edmonton.

4. RELOCATION OF THE APPROVED RIGHT OF WAY "WY"

4.1 Views of the Applicant

The City of Edmonton stated that the Mill Woods project was Canada's largest single municipal land bank planned urban community involving the Federal, Provincial and Municipal Governments and the primary objectives of the project were to make available homes for a population over 120,000 people in the best physical environment.

The City of Edmonton submitted that one of the major assumptions made in preparing the Mill Woods project concept report in the late 1960's and early 1970's was the relocation of the existing CP 904L transmission line and its right of way along "WX" and another 200-foot right of way owned but not being used by Calgary Power Ltd. along "WY". Negotiation had been carried out by the City of Edmonton with Calgary Power Ltd. on the relocation question at that time. Because of the social and economic benefits from the Mill Woods land assembly project, the City of Edmonton considered it could not wait for completion of relocation negotiations, and consequently the Mill Woods Project Concept Report was formally adopted by City Council in June 1971 assuming that the rights of way in question would be relocated to a new location near 15th Avenue. Since then the detailed planning, design and construction for the Subdivision had been carried out in accordance with that assumption. To date, the progress of the development of the Subdivision has been advanced to such a degree that to restructure the Mill Woods Project concept and to replan the Subdivision incorporating the approved transmission line in question would be not only extremely difficult but also very costly to the City of Edmonton and consequently to the future homeowners in the Subdivision.

The City of Edmonton stated that it believed the Board was not made fully aware of the status of this project at the time of the hearing of Application No. 7103.

4.2 Views of the Interveners

Calgary Power Ltd. stated that it would not object to the application providing the City of Edmonton would acquire all necessary lands at no further expense to Calgary Power Ltd. and would reimburse Calgary Power Ltd. for the losses which had been and would be sustained by virtue of the re-routing necessary to give effect to the application. Any changes in or departure from the route presently approved by the Board should not cause any increase in costs to Calgary Power Ltd. consumers.

4.3 Views of the Board

The Board agrees with the applicant that the Board was not fully informed of the status of the Mill Woods Subdivision at the hearing held in September, 1973. Subsequently, the Board was made aware of the desire of the City of Edmonton and Calgary Power Ltd. to reach an equitable agreement that would be in the public interest and would avoid most of the problems associated with the route "W-Y" through the Mill Woods Subdivision.

As the City of Edmonton and Calgary Power Ltd. have reached an agreement regarding compensation and other matters relating to the proposed relocation, and as there is no other party objecting to the relocation, the Board believes that the approval of the application is practical, reasonable and is also in the public interest.

5. DECISION

The Board has considered the application under section 13 of The Hydro and Electric Energy Act, not section 40 of The Energy Resources Conservation Act.

Having regard to the City of Edmonton's new evidence and the Board's responsibilities under section 13 of The Hydro and Electric Energy Act, the Board is prepared to issue an order requiring Calgary Power Ltd. to dismantle and relocate the subject transmission lines as applied for by the City of Edmonton.

The order is in the form set out in Appendix I and subject to the terms and conditions therein contained.

ENERGY RESOURCES CONSERVATION BOARD

Vernon Millard

Vernon Millard
Vice Chairman

DATED at Calgary, Alberta
July 16, 1974

APPENDIX I

THE PROVINCE OF ALBERTA

THE HYDRO AND ELECTRIC ENERGY ACT

ENERGY RESOURCES CONSERVATION BOARD

ORDER NO. Misc HE 7406

An order respecting Calgary Power Ltd.
240 kV Transmission lines through the Mill
Woods Subdivision in the City of Edmonton

WHEREAS the Energy Resources Conservation Board granted Permit and Licence No. CP 74-1 to Calgary Power Ltd., authorizing the construction and operation of a transmission line from the Sundance power plant to East Edmonton; and

WHEREAS the City of Edmonton applied to the Board for an order requiring Calgary Power Ltd. to relocate a portion of its said transmission line authorized by Permit and Licence No. CP 74-1; and

WHEREAS the Board considers the relocation of the said transmission line to be in the public interest.

THEREFORE, the Energy Resources Conservation Board, pursuant to The Hydro and Electric Energy Act, being chapter 49 of the Statutes of Alberta, 1971, hereby orders as follows:

1. This order amends Permit and Licence No. CP 74-1, insofar as the same is applicable thereto.

2. Calgary Power Ltd. (hereinafter called "the Operator") shall relocate that portion of its transmission line authorized by Permit and Licence No. CP 74-1, from the route "W-Y" to route "W-G-F-Y" as shown on Appendix A hereto attached.

3. The Operator, subject to the completion of construction pursuant to clause 2, shall dismantle that portion of its existing transmission line designated as CP 904L, between "W-X" as shown on Appendix A.

4. Subject to clause 11, the Operator may undertake and conduct such interm operations and procedures, including temporary connections to other lines, as may be necessary to comply with the provisions of this order, to ensure a minimum of interference with service of existing and permitted transmission lines.

5. The Operator shall notify the Board on or before October 15, 1974, of the description of the right of way obtained along the route "W-G-F-Y", and of the Operator's schedule for the completion of construction and energizing of the facilities.

6. The Operator shall satisfy the Board within 30 days of the completion of the relocation of the transmission lines that such relocation has been in accordance with the provisions of this order and The Electrical Protection Act and regulations and orders pursuant to that Act.

7. The Operator shall notify the Board within 30 days of the completion thereof, that transmission line CP 904L has been dismantled in accordance with clause 3.

8. The Board, upon the application of an interested person and upon such terms and conditions as it considers proper, may order the payment of such compensation as it may determine, in respect of the transmission line herein required to be relocated.

9. This order is subject to the approval of the Minister of the Environment No.   ERCB, hereto attached as Appendix B, and to the terms and conditions therein contained.

10. This order is subject to the approval of the Deputy Minister of Lands and Forests, hereto attached as Appendix C and to the terms and conditions therein contained.

11. (1) Subject to subclause (2), the Operator shall satisfy the Board within two years of the date hereof that construction and dismantling of the said transmission lines, in accordance with this order, has been completed.

(2) The Board, on its own motion or upon the application of an interested person, may stipulate such later date by which operations shall be completed, as it may consider suitable under the circumstances.

12. The Board may

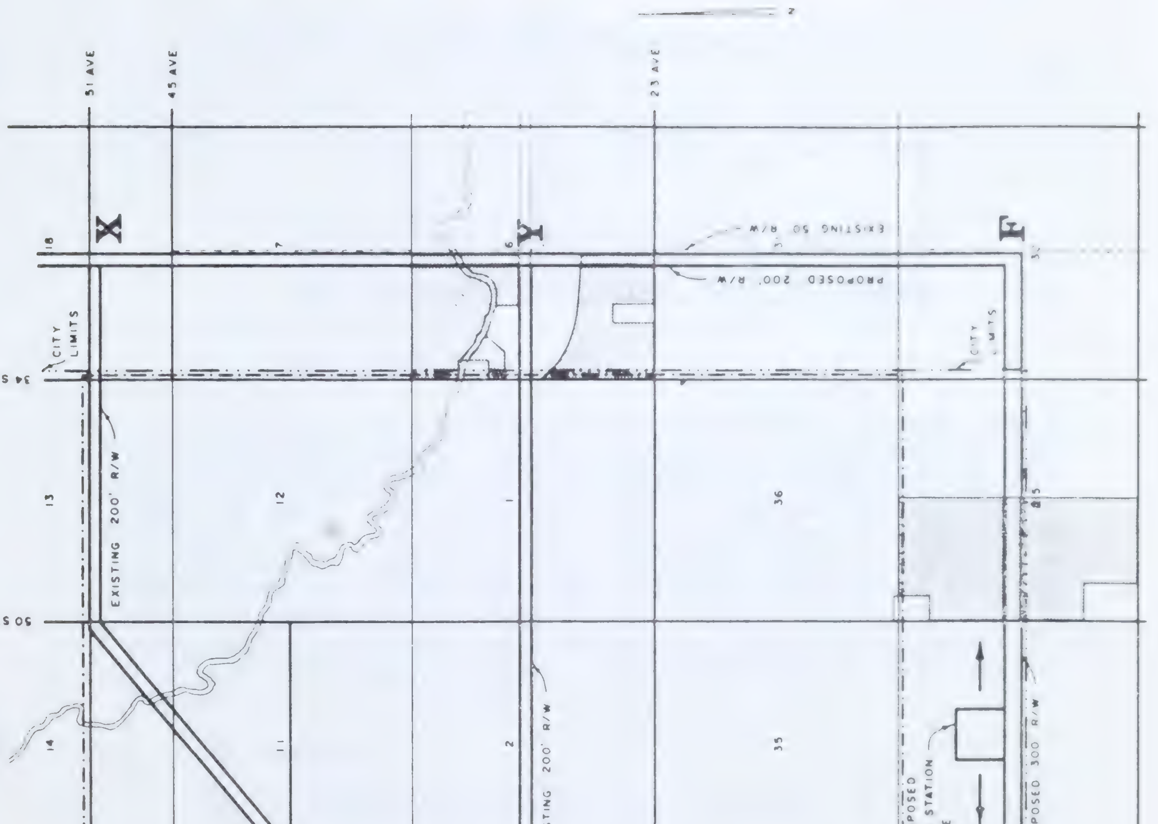
(a) rescind this order, in whole or in part, for failure of the Operator to comply with any provision of the Act, the regulations, or the terms and conditions set out herein, or

(b) amend this order as it deems suitable in the circumstances.

MADE at the City of Calgary, in the Province of Alberta, this

ENERGY RESOURCES CONSERVATION BOARD

J. I. Strong
Board Member


51 AVE
45 AVE
23 AVE
34 ST.
50 ST.
75 ST.
X
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16
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4
33
27
28
CITY LIMITS
EXISTING 200' R/W
PROPOSED 200' R/W
EXISTING 50' R/W
EXISTING 200' R/W
EXISTING 200' R/W
PROPOSED SUB STATION SITE
PROPOSED 300 R/W
MILL WOODS BOUNDARY
EXISTING SUB STATION SITE
91 STREET
PROPOSED 50' R/W
ELLERSLIE ROAD

ENERGY RESOURCES CONSERVATION BOARD

Decision 74-10
Application No. 7887

6-INCH PIPE LINE FOR THE TRANSMISSION OF SOUR NATURAL GAS FROM THE JUMPING POUND WEST FIELD TO THE QUIRK CREEK GAS PLANT

1. THE APPLICATION AND HEARING

Imperial Oil Limited applied under Part 2 of The Pipe Line Act for a permit to construct an approximately 33-mile long 6-inch pipe line for transmission of sour natural gas from the well, IOE JUMPW 11-16-25-6, located in Legal Subdivision 6 of Section 16, Township 25, Range 6, West of the 5th Meridian referred to herein as the "11-16 well", to its Quirk Creek Gas Plant located in Legal Subdivision 2 of Section 4, Township 21, Range 4, West of the 5th Meridian. The application was heard by the Board at Calgary on August 8 and 9 with D. R. Craig, P. Eng., V. Millard and N. Berkowitz sitting.

2. APPEARANCES

The following appeared at the hearing:

	Represented by	Witnesses
Imperial Oil Limited (Imperial)*	D. O. Sabey, Q.C.	D. J. McEachern J. T. H. Cochrane D. W. Stevenson C. C. Fortems I. L. Purdy
The Sarcee Indian Band and Sarcee Developments Ltd.	G. Pulak	P. Conrad W. J. Newis B. Horton L. Crane
Landowners	D. B. Mason, Q.C.	K. F. Copithorne
The Department of Indian and Northern Affairs	R. H. King	

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* Abbreviation used in this report.

	Represented by	Witnesses
City of Calgary	H. D. Hunter	
Board Staff	L. A. Bellows, P. Eng. K. G. Sharp, P. Eng. F. J. VanGinhoven N. A. Macleod, Q.C.	

Interventions were filed by the following:

(a) Petrasuk and Company on behalf of the Sarcee Indian Band and Sarcee Developments Ltd.,

(b) Paul K. Anderson,

(c) Mason and Company on behalf of the following group of landowners:

CL Ranches Ltd.
XC Bar Ranch Ltd.
Carl Lennart Kumlin
Wayne M. Sibbald and John F. Sibbald
Richard Francis Copithorne
Louis Ellis Copithorne
Margaret Winnifred Kumlin
David Copithorne

Interventions for the purpose of cross-examination and argument were filed by

(a) R. H. King on behalf of the Department of Indian and Northern Affairs,

(b) H. Douglas Hunter & Associates Ltd. on behalf of The City of Calgary.

3. BACKGROUND AND ISSUES OF THE APPLICATION

The Sarcee Indian Band questioned the jurisdiction of the Board to hear the application on the grounds that part of the proposed pipe line crosses the Sarcee Indian Reserve. The Band contended that reserve lands are not under Alberta's control, and that the consent of the Governor General in Council is required before a pipe line could be built or a right of way obtained on the reserve. The Board decided that it was not competent to determine the matter of jurisdiction and that the hearing should proceed.

The application is for a permit for a high pressure sour gas pipe line from a well in the West Jumping Pound field to a plant some 33 miles distant serving the Quirk Creek field. The applicant recognized the existence of a gathering system and processing plant in the West Jumping Pound field, and only decided to apply for the proposed pipe line after considering the two alternatives offered by

(a) processing the gas at the Shell Jumping Pound plant through participation in the Jumping Pound West unit, or

(b) constructing a small on-site gas processing facility.

Objections by landowners along the proposed route of the pipe line claimed that Imperial had not clearly demonstrated that the need for the pipe line overshadowed its detrimental effects on land values, cattle breeding operations, and proposed municipal developments on the Sarcee Indian Reserve.

In view of these objections, the Board believes the principal issue to lie in the need for the pipe line. Should it be satisfied on this matter, other issues would, in the Board's opinion, be

(a) the suitability of the proposed route, and

(b) the safety of the pipe line having regard for the proposed high operating pressure and hydrogen sulphide content of the gas.

With respect to the primary issue, the necessity of the pipe line, the Board thinks it important that the proposed pipe line be evaluated in the light of all reasonable options for processing gas from the 11-16 well. The applicant has examined two alternatives, but evidence at the hearing and subsequent Board investigations revealed several others. Among them are processing at the Jumping Pound plant for a fee rather than on a unit participation basis, processing at the Wildcat Hills plant or at a new plant contemplated by Phillips Petroleum, or exchanging gas with the owners of reserves in the Sarcee field, near the Quirk Creek plant, which is presently piped to the Jumping Pound processing facilities. In the latter case, gas from the 11-16 well would go through the Jumping Pound plant while Sarcee gas would be piped to Quirk Creek through a new but substantially shorter pipe line than that proposed in the application, resulting in a net reduction in the length of operating high pressure sour gas lines in the area. The location of the proposed pipe line and of other processing alternatives is shown in Attachment 2.

The Board believes that each alternative must be assessed in terms of

(a) conservation of resources,

(b) environmental impact,

(c) economics, and

(d) correlative rights.

4. CONSERVATION OF RESOURCES

4.1 Views of the Applicant

The applicant contended that processing gas from the 11-16 well at the Quirk Creek plant would prolong the economic life of the plant by four years, from 1993 to 1997, and consequently allow recovery of an additional 11.4 Bcf of gas from the Quirk Creek field. It argued that while recovery from the Jumping Pound fields would also improve if the gas were processed at the Jumping Pound plant, any gain would be marginal because the plant can optimize production from three fields rather than the one served by the Quirk Creek facility. Imperial acknowledged, however, that its calculations were based on present delineated reserves and took no account of the possibility of new gas reserves being developed in the area and processed at the Quirk Creek plant.

The applicant also stated that the technical design of the Quirk Creek plant makes its fuel requirements almost independent of throughput and that a fuel gas saving would therefore be realized if the gas were processed at Quirk Creek rather than elsewhere. Imperial provided no estimate of the fuel gas savings that would occur.

Imperial pointed out that because of sulphur recovery efficiency at the Quirk Creek plant, more sulphur would be recovered there than at the Jumping Pound plant or a smaller on-site facility.

4.2 Views of the Interveners

The interveners stated that the estimate of additional recovery of 11.4 Bcf of gas from the Quirk Creek field did not consider the possibility that gas from new gas discoveries in the area might be processed at the Quirk Creek plant. They also observed that additional recovery would be obtained in the Jumping Pound area if the gas were processed at the Shell Jumping Pound plant and that the 11.4 Bcf did not reflect a net conservation advantage.

4.3 Views of the Board

The Board is aware of the recent gas discoveries and continuing exploration in the Quirk Creek area and notes that there are also gas reserves in the Whiskey and Moose fields, near the Quirk Creek plant, which are not now being produced. The location of these fields in relation to the Quirk Creek plant is shown in Attachment 2. The Board further believes that additional gas reserves are likely to be developed in the Quirk Creek area before the plant reaches its turn-down point in 1993. If, as may reasonably be assumed, these other reserves come to be processed at the Quirk Creek plant, they would also provide the increased recovery of Quirk Creek gas to which Imperial referred in the application. The Board, therefore, cannot accept Imperial's contention that there would be realized a net gain in gas conservation solely attributable to the production of the 11-16 well to the Quirk Creek plant and agrees only that, compared with the alternatives considered by the applicant, processing at Quirk Creek would allow slightly higher sulphur recovery, modest savings of fuel gas, and perhaps some portion of the gas conserved by prolonging the plant life. With respect to other alternatives, which were not considered by the applicant and discussed at the hearing, the Board cannot fully evaluate the conservation effects.

In summary, the Board concludes that the proposed pipe line offers only modest conservation advantages over the other alternatives considered by the applicant.

5. ENVIRONMENTAL IMPACT

5.1 Views of the Applicant

The applicant stated that its methods for constructing and operating the proposed pipe line would have little adverse effect on the natural environment. Locations of major river and creek crossings were chosen to minimize land disturbance and possible erosion, and the possibility of a line break is remote. Disruption of landowners' operations would be minimized by confining construction to the winter months.

Imperial contended that because of higher sulphur recovery efficiencies, the Quirk Creek plant would emit at least 1.14 long tons per day less sulphur dioxide in processing 9.2 MMSCFD than the other alternatives. Imperial agreed, however, that the daily sulphur dioxide emission attributable to production from the 11-16 well processed at the Quirk Creek plant would exceed that which would occur from processing at the Jumping Pound plant where effective plant throughput on a unit participation basis would be unchanged.

The applicant stated that it was not aware of proposed housing development in the north-west corner of the Sarcee Indian Reserve, and that it would probably have selected a different route for that portion of the proposed line if it had been informed of the development.

5.2 Views of the Interveners

The interveners were concerned about the effect of the pipe line on future land development and about greater public access to previously inaccessible areas. They also expressed some anxiety about pipe line construction causing soil erosion on their property and about potential hazards associated with accidental release of sour gas.

The interveners questioned the applicant's contention that processing at the Quirk Creek plant would result in lower sulphur dioxide emissions.

The Sarcee Indian Band gave evidence that it was well advanced in planning an extensive housing development in the north-west corner of the Sarcee Reserve. Stage I of this urban-type development would be comprised of some 700 single family dwellings, related service facilities and a golf course. It would be bisected by the proposed pipe line, resulting, in the Band's opinion, in unnecessary safety hazards and adverse aesthetic effects.

5.3 Views of the Board

The Board observes that construction of a 33-mile long high pressure sour gas line will have some adverse environmental effects, whatever the route and the care taken in its design, construction and operation. The Board believes, however, that proper construction practices and full compliance with the standards set by the Department of the Environment for crossing water courses can minimize these effects. It notes, nevertheless, that the two alternatives, which would only require relatively minor changes to existing delivery systems, would be more acceptable from an environmental standpoint. The same may be true of other processing options which the applicant has not considered. For example, processing at the Wildcat Hills plant or at a possible new plant by Phillips Petroleum in the area, or exchanging gas with the owners of the Sarcee field, would require much shorter pipe lines than the one proposed in the application.

The Board recognizes that if gas from the 11-16 well were processed at the Quirk Creek plant, the daily incremental rate of sulphur emission would be higher than with restricted production and processing at the Jumping Pound plant. It does, however, accept Imperial's contention that higher sulphur recovery efficiencies at Quirk Creek will result in slightly lower cumulative emission than either of the two alternatives considered by the applicant. In any event, each processing scheme would have to meet the Board's sulphur recovery guidelines as well as the emission control and ground level concentration standards of the Department of the Environment.

With respect to safety considerations, the Board believes that while overall risks are minimal, the proposed pipe line should not traverse the area of proposed housing developments on the Sarcee Indian Reserve. Should the Board be otherwise satisfied respecting the proposed route it would make this a condition of any permit issued.

In summary, the Board concludes that the proposed pipe line has significant disadvantages in terms of environmental impact and safety when compared with other options.

5.4 Position of the Department of the Environment

The position of the Department of the Environment is presented in Attachment 1.

6. ECONOMICS

6.1 Views of the Applicant

Imperial stated that the initial capital costs of the proposed pipe line would be $3.32 million, and that a further investment of $800,000 would be required in 1983 for 500-brake horsepower of compression facilities. For the on-site plant, an initial capital investment of $4.26 million, with an additional expenditure of $932,000 in 1985 for 500-brake horsepower of compression, was given. For the unit participation alternative, the applicant estimated an initial investment of $250,000 for tie-in and its share of sales compression, with subsequent investments of $2.146 million for unit infill wells between 1980 and 1986, and $496,000 for its share of 3,000-brake horsepower compression in 1987.

Total capital investments for the three alternatives were given as:

Pipe line to Quirk Creek	- $4.12 million
On-site plant	- $5.192 million
Jumping Pound West unit participation	- $2.89 million

Annual operating costs were estimated by Imperial at some $76,000 for the pipe line and $490,000 for the on-site facility, in both cases escalating at 5 per cent per year, and no incremental operating costs would be incurred at the Quirk Creek plant if gas from the 11-16 well were processed there. For unit participation, the initial operating cost was $9,000 escalating at 5 per cent per year until installation of compression in 1987, when annual costs would increase to $64,000 per year. In addition, 12.1¢/Mcf, increasing to 45.1¢/Mcf in the year 2002, would be payable for use of the Shell Jumping Pound plant.

Although the applicant declined to disclose the gas price forecasts on which it based its revenue estimates, it gave the present value advantage of the proposed pipe line as $2.4 million after taxes over Jumping Pound West unit participation and $1.2 million over an on-site facility. Imperial also stated that the present worth of the proposed project was between $8 million and $8.5 million, and that gas prices are quite unlikely to escalate at rates that would offset the present worth advantage of the pipe line. Based on this analysis, it concluded that the pipe line to Quirk Creek was the most economic choice for producing the subject well.

Imperial contended that the landowners' objections to the proposed pipe line merely reflected their wish to maximize the value of their investments and that they should not be critical of Imperial for wishing to do the same.

6.2 Views of the Interveners

The interveners questioned the applicant's economic evaluation and argued that Imperial had not adequately demonstrated the optimum economic value of the gas for the people of Alberta. Since it had only examined the Jumping Pound processing alternative on a unit participation basis, the interveners contended that economic investigations had not progressed sufficiently to justify the pipe line. It was further stated that bisection of a planned community on the Sarcee Indian Reserve by a pipe line right of way would result in a direct loss of $300,000 and that the loss to right of way of several building lots would cause higher taxes per developed lot. As well, a sour gas pipe line would make the area less desirable for prospective residents, and consequently cause other intangible economic losses.

Interveners represented by Mason and Company also expressed concern about the pipe line right of way providing greater access to their previously isolated cattle operations. They pointed out that the resulting public disturbance would cause problems with cattle breeding programs and associated monetary loss. The landowners also contended that the area directly west of the City of Calgary to the Morley Indian Reserve is a highly attractive potential recreation or subdivision area and that the proposed pipe line would detract from its aesthetic appeal.

H. D. Hunter implied that part of the incremental profit of the proposed pipe line over alternatives considered by the applicant resulted from Imperial not imposing a cost of processing or tariff on gas processed at the Quirk Creek plant.

6.3 Views of the Board

The Board agrees that under the conditions outlined in the application, the proposed pipe line provides a significantly larger net return than either of the two alternatives. The applicant assumed that future gas reserves in the Quirk Creek area would not be processed at the Quirk Creek plant and, consequently, that the processing agreement among the owners of the plant would allow the applicant to process its West Jumping Pound reserves at no additional cost. However, as already noted, the Board does not agree with the assumption that no additional reserves from the Quirk Creek area will be processed in the Quirk Creek plant. While it recognizes that such additional reserves may not be developed by the applicant, it nevertheless believes that it would be reasonable and in the public interest to have such reserves processed at the partially-loaded Quirk Creek plant rather than duplicating transmission lines and processing facilities in an area that is valuable for agricultural, suburban development and recreational purposes. The Board concludes therefore that additional Quirk Creek area gas likely will be processed in the Quirk Creek plant and that it would be charged its fair share of total processing costs, especially if it is developed by a third party. Processing of Quirk Creek area gas should consequently provide the plant owners with significant future revenues, and any comparison of the relative costs of alternatives for processing the applicant's gas from the 11-16 well must take account of this by including a charge for processing at the Quirk Creek plant.

No evidence about processing costs was presented at the hearing. However, a basis for making an adjustment to the applicant's economics is afforded by the Board's records which indicate that reasonable processing charges range from 8 to 12 cents per Mcf. Thus, assuming escalation of costs at 5 per cent per year and applying a 10 per cent discount rate, the low end of this range - 8 cents per Mcf - leads to a present value processing cost of $3.1 million for the production rates contemplated by the applicant. For a still lower cost - 5 cents per Mcf - which may apply in certain unusual circumstances, a similar calculation indicates a present value processing cost of $2.0 million.

Proceeding from these calculations, the Board has re-examined Imperial's incremental present values for the two alternatives to the pipe line scheme which was considered. For a processing cost as low as 5 cents per Mcf, the Board finds that an on-site facility would have a $0.80 million present value advantage over the proposed pipe line scheme, while unit participation in the West Jumping Pound plant would have a $0.4 million disadvantage. If the processing cost is put at 8 cents per Mcf, the on-site plant would have a $1.9 million advantage and unit participation in the West Jumping Pound facility a $0.7 million advantage over the proposed pipe line scheme.

The Board accordingly concludes that any reasonable allowance for the cost of processing the applicant's West Jumping Pound gas at the Quirk Creek plant would favour the on-site plant alternative over either of the other two considered by Imperial.

As the Board understands it, the major reason for the unadjusted present worth benefits of the pipe line over unit participation is the substantially higher rate of gas production in the pipe line case, and the processing fee that would be charged if the gas were processed at the Jumping Pound plant. While the gas purchase contract allows a production rate of some 9.2 MMSCFD, the unit participation plan offered to Imperial provides only for an annual rate of 3 MMSCFD during the first five years, increasing over a 2-year period to 7.1 MMSCFD, producing at that rate during the following 10 years, and reduction thereafter to a cumulative production of 49 Bcf of residue gas. The serious impact of the lower production rate on the present worth of unit participation could be substantially avoided by a processing agreement with the operators of the Jumping Pound plant which allowed greater production rates. Although the applicant contended at the hearing that plant limitations prevented this, there was some uncertainty about the actual situation, and Imperial stated that it had not made any specific inquiries of the plant operator.

The Board believes that aside from the direct costs associated with the various alternatives, some indirect and intangible costs must be recognized. While there is insufficient data to quantify such costs as impact on land values, the Board considers that the proposed 33-mile sour gas pipe line would result in substantially higher indirect costs than an on-site facility or unit participation in the Jumping Pound plant.

The Board does not have sufficient data to estimate the costs of processing the applicant's gas through the additional alternatives referred to in section 3.

In summary, the Board does not agree with the applicant's conclusions regarding the relative economic advantages of the alternatives it considered. From the limited information presented at the hearing and on the basis that gas processing charges should be applied to the gas transported to the Quirk Creek plant, it appears to the Board that the on-site plant is more economic. The Board recognizes, however, that other options - particularly processing at the Shell Jumping Pound plant through a processing agreement rather than unit participation - may offer even greater advantages, and that these alternatives ought to be further studied.

7. CORRELATIVE RIGHTS

7.1 Views of the Applicant

The applicant noted that delayed production of the well would result in drainage of reserves by other owners in the Jumping Pound West field. No estimate of the rate of drainage was presented, but Imperial stated that its share of the gas through unit participation would be 49 Bcf to the year 2002, whereas its share for the other two cases would be approximately 52 Bcf.

7.2 Views of the Interveners

R. H. King implied in a question that delayed production from the 11-16 well would result in some drainage of the well's reserves by other owners in the Jumping Pound West unit.

7.3 Views of the Board

The Board agrees with the applicant that correlative rights would be protected by putting the 11-16 well on production as soon as possible and that delaying production from it could result in some drainage of the well's reserves by other owners.

8. FINDINGS

(1) Conservation of Resources:

The Board accepts that there would be some conservation advantage in processing the gas from the 11-16 well at the Quirk Creek plant, but believes the advantage would be less than stated by Imperial.

(2) Environmental Impact:

The Board believes that while the pipe line to Quirk Creek provides for lower cumulative sulphur dioxide emissions, it has significant environmental and public safety disadvantages over the alternatives considered.

(3) Economics:

The Board does not agree with the basis of the applicant's economic evaluations. With the limited data presented at the hearing, and its appraisal of the relative economics of the alternatives, the Board believes that a small on-site processing plant could be more economically attractive. Further, the Board is satisfied that an on-site plant would provide the applicant with a reasonable economic opportunity to process gas from the 11-16 well. The Board is not satisfied that other alternatives have been sufficiently explored.

(4) Correlative Rights:

The Board recognizes that Imperial is entitled to produce gas reserves developed by it, and that the proposed pipe line offers the most direct means of processing the gas. All other alternatives would involve either a delay in implementation or depend upon satisfactory negotiations with other owners.

(5) Pipe Line Route and Safety:

The Board agrees that the route for the proposed pipe line has been selected with due care, but regards as unacceptable that portion which extends from the vicinity of the north-west corner of the Sarcee Indian Reserve to the existing condensate pipe line right of way. The Board accepts as adequate the design of the proposed pipe line, but believes that the line should not cross the proposed residential development, recognizing that there would be some hazard in the presence of the proposed pipe line, however well designed it might be.

(6) Overall Public Interest:

Having regard to the modest conservation advantages, to the significant impact on the environment when compared to possible alternatives, to the absence of evidence that the pipe line is needed to provide an economic opportunity to process gas from the 11-16 well, to the apparent economic advantage (based on limited data) of an on-site plant, and to the potential - albeit small - hazard to life and property, the Board finds that the proposed pipe line is not in the public interest.

9. DECISION

The application is dismissed with leave to the applicant to reapply when all unresolved matters of concern have been investigated.

ENERGY RESOURCES CONSERVATION BOARD

D. R. Craig
Vice Chairman

Attachments

DATED at Calgary, Alberta
November 15, 1974

ATTACHMENT 1

DEPARTMENT OF THE ENVIRONMENT POSITION
APPLICATION NO. 7887

Imperial Oil Limited
Sour Gas Line
Jumping Pound to Quirk Creek

1) Imperial Oil proposes to construct a pipe line from LS6-16-25-6-W5 to LS3-4-21-4-W5 to convey dehydrated sour process gas from a single well to their processing plant in the Quirk Creek area.

2) Said pipe line is approximately 34 miles long and 6 inches in diameter.

3) The pipe line would cross the following significant streams

   1. Elbow River
   2. Jumping Pound River
   3. Little Jumping Pound Creek
   4. Priddis Creek
   5. Fish Creek
   6. Whiskey Creek
   7. Fisher Creek

4) The pipe line runs through an area of generally steep slopes, crossing many coulees and hills. These areas are mainly treed or grassed, and if scarred by pipe line construction, would require very stringent soils handling and erosion control techniques.

5) The pipe line traverses an area of valuable watershed for the Elbow and Bow Rivers. The Department would like to see everything reasonably possible done to retain the watershed characteristics that are present. The building of a pipe line while only affecting a small part of the total shed, would nonetheless be a contributing factor to the degradation of the watershed characteristics.

6) The pipe line would scar an area of approximately 165 acres, assuming an average 40 foot width of construction area. In most pipe line installations, it is hard to keep the right of way to such a narrow strip and the machines ultimately spoil more.

7) The possibility of a gas leak, although remote, is still present. The effects of a particular leak are very speculative, as so many factors are involved in prediction. A one mile length of 6 inch pipe contains sufficient sour gas to cause problems if weather conditions and the type of rupture are not favourable.

The Department of the Environment is of the opinion that this pipe line should not be built unless it is undisputably shown that there is no other way Imperial's gas can be processed. It should be economically and physically possible to have the gas processed in the local field instead of transporting it some 34 miles.

Relatively, this pipe line may be no more harmful to the environment than many others already built or to be built in Alberta's foothills. The fact remains that there appears to be a reasonable alternative. The Department feels that this is the time to take that alternative.

ATTACHMENT 2

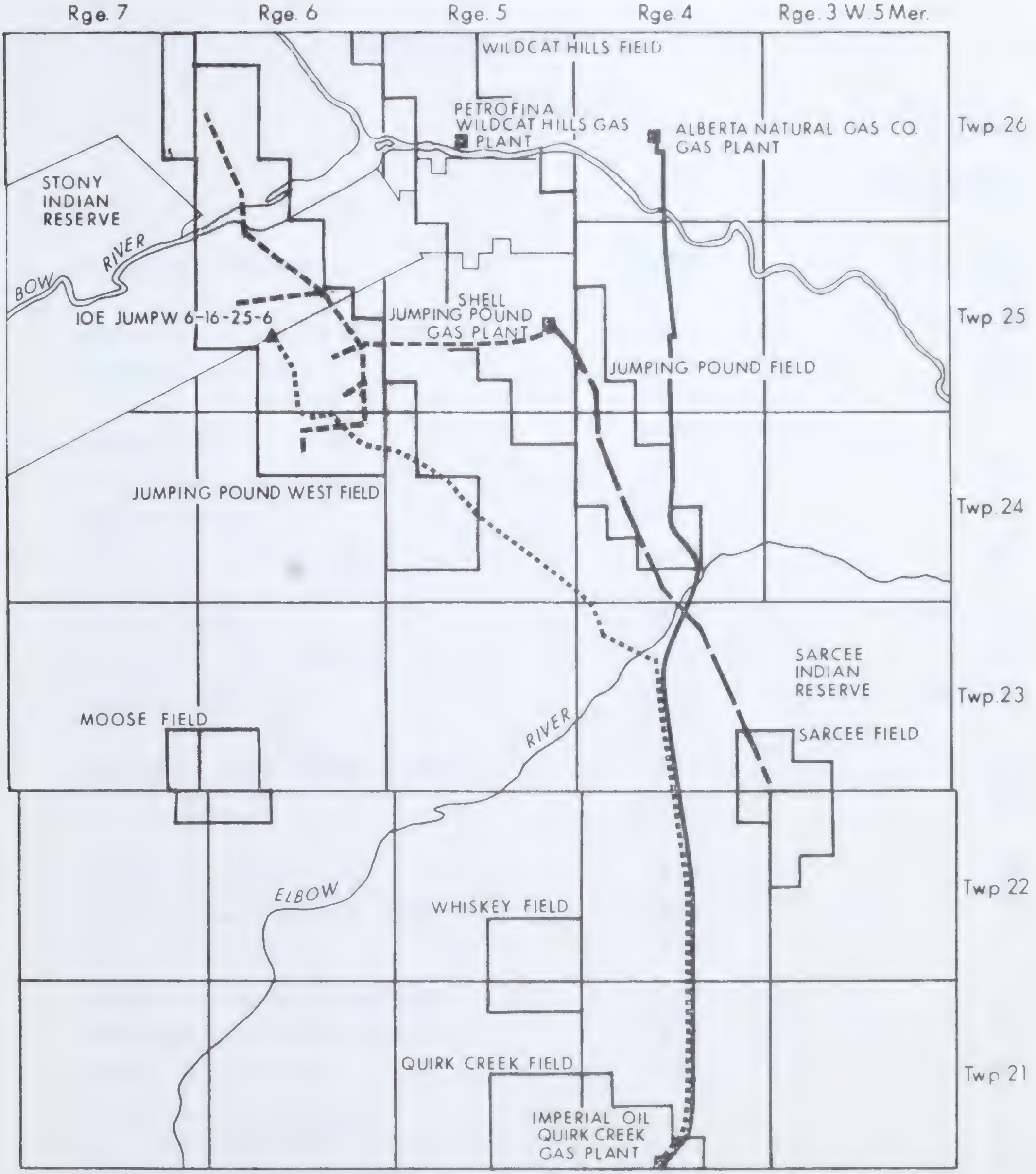

FIGURE 1 - APPLICATION 7887
LOCATION OF THE PROPOSED PIPE LINE

·············· PROPOSED ROUTE OF SECONDARY LINE FOR SOUR NATURAL GAS
———————— EXISTING 4" CONDENSATE LINE
— — — EXISTING 8" SOUR GAS LINE
- - - - - - - - EXISTING SHELL GAS GATHERING SYSTEM

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